PROCEDURE FOR MAKING A SECTIONALIZING STUDY ON RURAL ELECTRIC SYSTEMS

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CHAPTER I

INTRODUCTION

A. General

This bulletin outlines a procedure for making sectionalizing studies on REA systems, and contains suggestions for selecting and locating sectionalizing equipment. Sectionalizing studies are not difficult, but a study is always advisable before equipment is purchased or installed.

All analyses not specifically pertinent to rural circuits have been eliminated, resulting in complete and definite instructions for a sectionalizing study on a rural system of the REA type. The bulletin is written partly in the form of a textbook and partly in the form of instructions on method and procedure. Every effort has been made to make the text as simple as possible; knowledge of symmetrical components, or even of vector algebra, is unnecessary. Sample problems are given to aid in understanding the text.

It is advisable to read the entire paper and go through the examples before attempting an actual study. In order to provide ease in checking, engineers making sectionalizing recommendations to REA projects should submit the study in the same general forms shown herein employing either the mathematical or the graphical methods of calculating fault currents. The listed impedance values for the mathematical method or the impedance curves for the graphical method contained in this bulletin must be used unless local conditions or other factors indicate that such is not advisable. In these cases, the engineer should submit the basis for his study, and the reasons for such differences.

The engineer familiar with symmetrical components will find that some of the formulas in this text have a different form than the familiar ones. These changes have been made in the interest of simplicity for the special case of REA systems. For the purpose of simplification, various limitations were established. These simplifications and limitations are explained in the text, and should be noted carefully by anyone solving an actual problem.

Such factors as decrement, automatic voltage regulators, load, etc., have been neglected or assumed in the outline, since too much labor is required to accurately evaluate these effects. For ordinary work, the slide rule is sufficiently accurate for all practical purposes.

The engineer should take care in using special slide rules or nomographs in calculating fault currents on REA projects, since most of these devices are not calibrated for calculations on multigrounded circuits, and also such devices are based on the assumption that the impedances may be added algebraically.

Typical decrement curves in handbooks should also be used with caution, as these neglect circuit resistance and assume no automatic voltage regulation.

B. Summary of Steps in Sectionalizing

1. Obtain complete data on the power system and on the proposed devices before starting a study. See pages 2 to 7.

2. After study of the lines, both on the map and in the field, and talks with the operating personnel, make a tentative location of the sectionalizing devices. See page 7.

3. Calculate maximum and minimum fault currents at each tentative sectionalizing point, and at the ends of the lines. Calculate line-to-ground, three phase, and line-to-line fault currents. See pages 8 to 15, and pages 73 to 87.

4. Select the devices at the substation to give complete and adequate protection to the substation transformers from fault currents on the lines. See pages 16 to 20.

5. Coordinate the sectionalizing devices from the substation out, or from the ends back to the substation. Revise the tentative locations if necessary. See pages 20 to 27.

6. Check the selected devices for current carrying, interrupting and minimum pickup rating. See page 27.

7. Prepare written instructions and a circuit diagram for the operating personnel of the project. See pages 28 to 29.

8. If requested work out instructions to the project for maximum service lengths on various sizes of distribution transformers. See pages 30 to 34.

C. Data Necessary.

In order to make a complete sectionalizing study of a project, definite data on various items must be obtained relative to the project. These items are outlined on Form TS-5, following. All of these data should be available before attempting a study, as lack of any will delay the work.

If for a small REA or municipal plant, the data on machine reactances cannot be obtained, the approximate values shown on page 10 may be used.

It is also necessary to obtain time-current characteristics for all sectionalizing devices used on the project. These are explained more in detail later. (See page 16)

<u>WHEN SENDING IN A STUDY TO REA FOR CHECKING, BE SURE TO INCLUDE A COPY OF ALL OF THESE DATA.</u>

Form TS-5R1
12-3-45

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL ELECTRIFICATION ADMINISTRATION

DATA REQUIRED FOR COMPLETE SECTIONALIZING STUDY
(Omission of any item will handicap the study)

I. Circuit Diagram of entire system (Two copies.)

This should be prepared in accordance with Engineering Memorandum Number 154. In addition, the location of any transformers protected by gaps instead of arresters and any consumer or group of consumers to whom a lengthy power interruption would be costly and detrimental should be noted.

Fault currents and recommended sectionalizing devices are shown on the circuit diagram as the study progresses.

II. Substation Information

A. Diagram of Substation

Show transformers, all outgoing lines at the substation and within one mile of it, and the location of every sectionalizing device on these lines. This should be a sketch not to scale. (See back page for sample).

B. Other Data (Obtain from transformer nameplate.)

1. Capacity each transformer, KVA__________
2. Percent reactance each transformer__________
3. Percent resistance each transformer__________
4. Percent impedance each transformer__________
   (If single 3-phase transformer is used, give above data per phase.)
5. Exact voltage, line to line, supply side__________
6. Exact voltage, line to ground, REA side__________
   (If there is more than one substation, give the above data for each one.)

III. Information Concerning Power Supply
(Answer A or B, depending on source.)

A. Private Utility or large municipal plant
(Obtain this data from the power source organization.)

1. Name of Utility__________
   Address__________
2. Fault Table

Line to line voltage on supply side at Substation__________Volts

	Short circuit currents on supply side of substation under normal operating schedule: Maximum	Minimum
Line to line fault current, Amps.		
Three-Phase fault current, Amps.		

3. Power Company Requirements:

For fuse on supply side:
Maximum fuse size allowed by power supply organization__________
Make of fuse__________ Catalog Number__________

For breaker on supply side:
Maximum current setting on breaker or relay allowed by power supply organization__________
Maximum time lever setting__________
(See also IV)

B. Small Utility, Municipal Plant, or REA Power House

1. Name of organization supplying power ____________________

   ____
   Address ____________________
2. Give distance between the substation and the power house in miles.
3. Size and kind of conductor between the substation and this plant

   ____
4. Plant data

   a. Operating characteristics of Generators

UNIT NO.					
Make of Generator					
Serial Number					
KVA Capacity					
% Direct Axis Transient Reactance					
% Direct Axis Synchoronous Reactance					
% Negative Sequence Reactance					
Type of Prime Mover					
Speed in RPM					

   b. Units running under normal Operating Schedule
      1. During minimum load ____________________
      2. During Maximum load ____________________

   c. Line to line Voltage ____________________
5. For fuse on supply side:

   Maximum fuse size allowed by power supply organization __________

   Make of fuse __________ Catalog number __________

   For breaker on supply side:

   Maximum current setting on breaker or relay allowed by power supply organization ____________________

   Maximum time lever setting ____________________

   (See also IV)

IV. Equipment Information

A. Circuit Breakers and Control

Location:	Line	Substation: Load Side	Substation: Supply Side	Feeder in ** Power Plant	Other(Specify)
Breaker Manufacturer					
Breaker Type or Style No.***					
Breaker Operating Handle, Style No.					
Current Time-delay dashpot (yes or no)					
Present Current Trip setting					
Control-Relay	1*				
Manufacturer	2*				
Control Relay Type	1*				
or Style No.	2*				
Present Relay	1*				
Tap Setting	2*				
Present Relay Time	1*				
Lever Setting	2*				
Relay Current	1*				
Transformer Ratio	2*				
Is the breaker automatically reclosing?					
Other Details (Specify)					

If no breakers are in use, write "none".

*If more than one type of relay controls the breaker (as overcurrent and ground), separate these on lines 1 and 2 for all items. If no relay is used, put none in proper space.

**Fill in this column only if receiving power from REA plant, municipal plant, or small utility. Correlate with diagram of power house.

***Number on breaker tank.

B. Fuse Links

Location:	Distribution Transformer	Line Sectionalizing	Substation Load Side	Substation Supply Side
Fuse Manufacturer				
Catalog or Style No.				

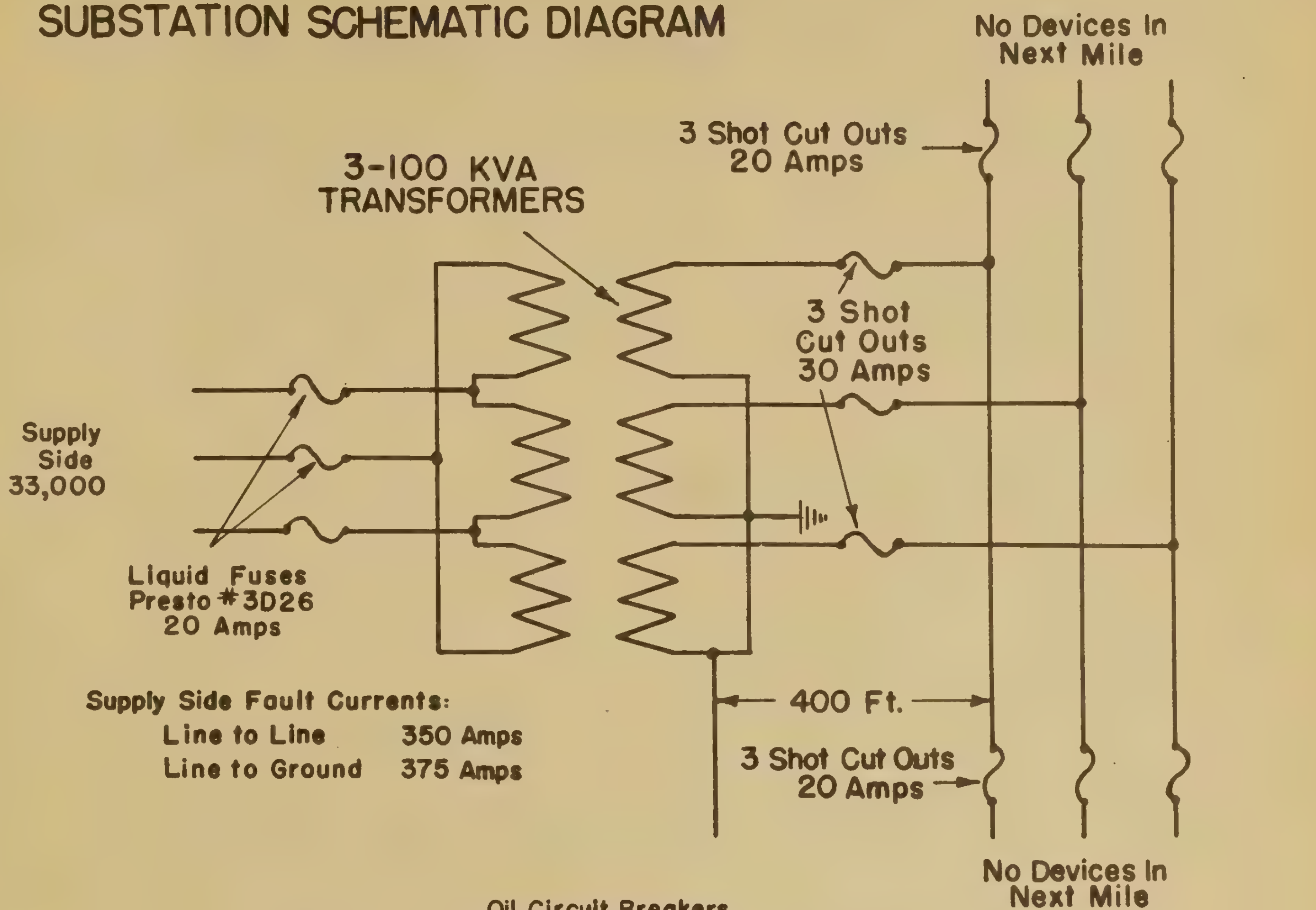
(List here the fuses which you would like to have standardized on your project)

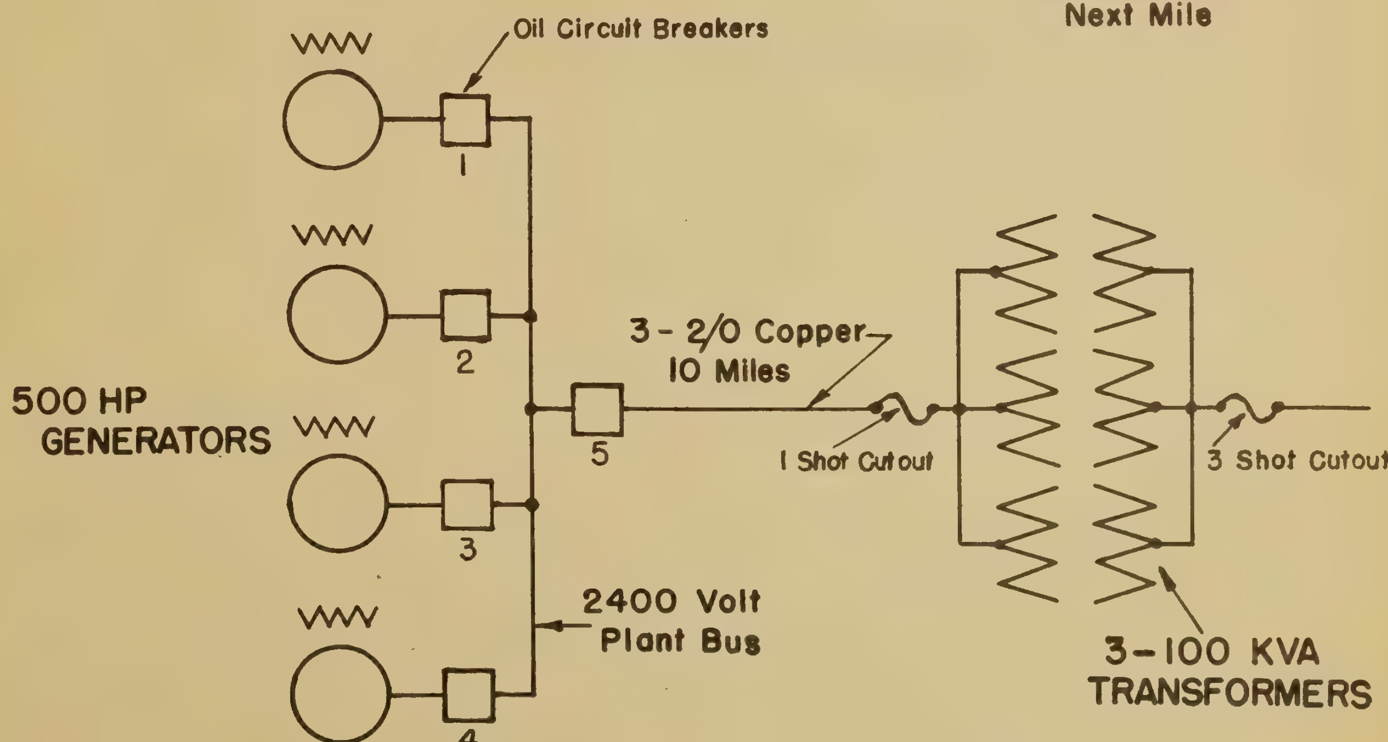
V. Description of Difficulties

A. Describe in detail on the reverse side what difficulties have been experienced with the present sectionalizing arrangement.

SAMPLE DIAGRAMS

SUBSTATION SCHEMATIC DIAGRAM





ONE LINE DIAGRAM

D. Location of Sectionalizing Devices

The first step is to make a tentative location of sectionalizing devices. These tentative locations may be revised after the short circuit currents are calculated. Individual judgment must be used for each case, but the following points may be helpful:

1. If two or more main feeder lines go out from the substation, a sectionalizing device should be placed on each line. In other words, trouble on one line should not affect other main lines. In many cases, a set of cut-outs, or breakers for each line, will be preferable to only one set of cut-outs or breakers for the entire substation. In some cases, a quarter or half-mile of double circuit line with one circuit overbuild will allow a division of feeders at the substation, with consequent operating advantages. The substation should be designed with this in mind.

2. Branch lines over 4 or 5 miles in length should have sectionalizing devices. (Exceptions: where reclosing breakers or fuses are used.)

3. Where main lines branch, a sectionalizing device should be used in each line at the junction point.

4. The device should be accessible from highways open the year around.

5. The device should protect important loads (be beyond the transformer feeding the load.)

6. Any branch line exposed to hazardous conditions (trees, etc.) should be separated from the remainder of the system by a reclosing device, if possible.

7. The device should be located near a member with a phone, if possible.

CHAPTER II
CALCULATION OF FAULT CURRENTS

A. General

The next step is to calculate the approximate short-circuit currents on the system. IMPORTANT - this discussion will assume a 60-cycle system with multigrounded neutral conductor with substation transformers connected delta on the supply side and wye on the load side. The REA system is also considered radial (i.e., no connected loops). If there is more than one source of supply, these are not interconnected. For any other conditions, do NOT use the following formulas, but write REA, giving details.

Two types of fault currents should be computed, the maximum fault current and the minimum fault current. The former assumes all generating machines are connected, and zero fault resistance. The latter assumes the minimum number of generators, and some fault resistance. These fault currents should be computed for each sectionalizing point, including the substation, and at the ends of the longest sections.

It is generally possible, after some practice, to estimate fault currents for intermediate points with sufficient accuracy after a number of representative faults have been calculated.

Fuses are usually coordinated using the maximum fault currents. Minimum currents are used to make certain that reclosing circuit breakers, fuses and other sectionalizing devices will operate satisfactorily under all conditions. In particular, the substation transformers must be protected against all fault currents on the system. Although the general method of calculation is the same for both maximum and minimum fault values, the immediate discussion will concern the maximum values.

There are four possible types of faults, three-phase, double line-to-ground, line-to-line, and single line-to-ground. The first can occur only on three-phase circuits, and the second and third on three-phase or V circuits. Even on these circuits usually only single line-to-ground faults will occur, due to the multigrounded construction.

This discussion will cover methods of calculation for line-to-ground, three-phase and line-to-line faults. For double line-to-ground faults, reference is made to "Symmetrical Components", by Wagner & Evans, McGraw Hill.

B. Symbols

The following set of symbols is used.

I_s (L-L) = Line-to-line fault current in amperes on supply side at the substation.

E_s (L-L) = Line-to-line voltage in volts on supply side of substation.

I_{3s} = Three-phase fault current in amperes on supply side of substation.

I_L = Fault current on load side (REA side).

E_L = Line-to-ground voltage on load side (REA side) of substation.

R_s = Equivalent resistance per phase of source at load (REA) voltage.

X_s = Equivalent reactance per phase of source at load voltage.
Z_s = Equivalent impedance per phase of source at load voltage.
R_t = Resistance per phase of substation transformers at load voltage.
X_t = Reactance per phase of substation transformers.
Z_t = Impedance per phase of substation transformers.
R_L = Resistance per phase of REA distribution line (multigrounded).
X_L = Reactance per phase of REA distribution line (multigrounded).
Z = Total impedance per phase of distribution line, source and substation.
X_1, X_2, X_3 = Reactances of individual machines at load voltage (either direct axis transient or negative sequence).
X_m = Resultant reactance of all machines running in parallel.
n = Number of machines.
KVA_1 = KVA capacity of individual machine (total).
KVA_t = Total KVA capacity of all machines.

The fault current which flows will be equal to the voltage E_L divided by the impedance to the point of fault.

There are three main components of the impedance to the fault: (1) the impedance of the source; (2) the impedance of the substation, and (3) the impedance of the REA distribution lines.

C. Line-to-Ground Fault Currents

1. Source Impedance

(a) Large system

$$Z_s = \frac{(E_L)^2}{I_s\,(L\text{-}L)\,E_s(L\text{-}L)} \quad \text{Ohms.} \qquad (1)$$

Note: assume R_s 0, or take an appropriate ratio between R_s and X_s based on judgment.

If only the three-phase fault current is given,

$$Z_s = \left(\frac{2}{\sqrt{3}}\right)\left(\frac{(E_L)^2}{I_{3s}E_s(L\text{-}L)}\right) \qquad (1a)$$

(See note above)

If the supply side positive sequence impedance, Z_1, is given in ohms,

$$Z_s = 2Z_1 \left(\frac{E_L}{E_s(L\text{-}L)}\right)^2 \qquad (1b)$$

(b) Small system or REA plant

$$X_1\ (\text{ohms}) = \frac{X_1\ (\text{Percent})\ (E_L)^2(3)}{KVA_1\ \ (100{,}000)} \qquad (2)$$

(Use X_1 = direct-axis transient reactance for maximum fault current)

X_2 and X_3 can be found in a similar manner.

$$\text{Then, } \frac{1}{X_m} = \frac{1}{X_1} + \frac{1}{X_2} + \frac{1}{X_3} + \text{- - - -} \qquad (3)$$

If all machines are alike, $X_m = \frac{X_1}{n}$. (n should be maximum for maximum fault current) (3a)

Next determine the negative sequence reactances by using formulas (2) and (3) above, only with the percent negative sequence values.

$$\text{Then } X_s = \frac{(X_m \text{ (transient)} + X_m \text{ (neg. seq.)}}{3} \qquad (4)$$

X_m values must be in ohms.

If machine reactances are not obtainable, the following values may be used for approximation. (To be used only with discretion.)

Slow speed Diesel or reciprocating steam engine driven generators:

(1) Direct-axis transient reactance = 35%
(2) Negative sequence reactance = 22%
(3) Synchronous reactance = 110%

Non - salient pole turbine - driven generators
(1) Direct-axis transient reactance = 2 pole 15% 4 pole 23%
(2) Negative sequence reactance = 2 pole, 11% 4 pole 16%
(3) Synchronous reactance = 110%
Machine resistance can be neglected.

If the plant is some distance from the REA substation, the resistance and reactance of the tie line must be obtained. This can be done by using handbook values (see Standard Handbook for Electrical Engineers, McGraw Hill, for example) for the resistance and reactance of the line, using the conductor sizes and spacings of the line. Simply multiply twice the line distance in miles by the resistance and by the reactance (positive sequence) of the line per phase per mile. Convert each of these values separately to REA voltage by multiplying each by

$$\frac{E_L^2}{(E_s \text{ (L-L)})^2}$$

The above assumes a constant voltage along the time line. If there is another voltage transformation in this tie line, the resistance and reactance of each section should be computed as above, using the voltage for each section. For any transformer in the tie line, add 2/3 of the transformer impedance per phase calculated as shown by formula 5, below.

The same methods can be used for any transmission line.

The total X_s equals X_s from (4) plus the reactance determined above for the tie line amd R_s equals the resistance as determined above.

2. Substation Transformer Impedance

$$Z_t \text{ (ohms)} = \frac{Z_t \text{ (percent) } (E_L)^2}{\text{(kva per phase) } (100{,}000)} \qquad (5)$$

$$\left.\begin{aligned} X_t &= 0.98Z_t \\ R_t &= 0.20Z_t \end{aligned}\right\} \text{ approximately}$$

If Z_t is not known, approximate $Z_t = 5\%$ for transformers 100 KVA or over
$Z_t = 4\%$ for transformers less than 100 KVA

3. REA Line Impedance

To find the line-to-ground impedance to any point on the system, use the following values of impedance per mile:

Copper Conductivity Size	R_L	X_L	
1/0	0.72	1.12	per mile
2	1.00	1.22	" "
4	1.63	1.31	" "
6	2.45	1.46	" "
8	3.74	1.55	" "
9½	5.04	1.67	" "
11	7.36	1.70	" "

Note: The above impedance values are for multigrounded lines and are average values. If more accuracy is desired, use the appropriate values in the single phase impedance column of Table II titled "Impedance of REA Lines - Standard REA Spacings", page 42.

It is usually only necessary to carry line impedance values to the nearest 0.1 ohm.

Multiply each of the above values by the number of miles of each conductivity size from the substation to the point being considered.

(A table is given which will facilitate this. See Table I for Average REA Single Phase Line Impedance, page 41).

If two or more different sized conductors are used from the substation to the point, add the total resistance to the first size to the resistance of the next size to the point, and add the total reactance of the first size to the reactance of the next size, etc.

For neutral conductors of not more than two sizes less than the phase wire, use impedance values of the phase wire size since the circuit impedance of multigrounded neutral lines is only slightly influenced by the impedance of the neutral conductor.

4. Total of Impedances

To find the total impedance to each point, add the reactance of the source as determined under 1, to the reactance of the substation transformer, 2, plus the reactance of the REA line, 3. Add the resistance of the source, 1, to the resistance of the substation, 2, plus the resistance of the REA line to the point, 3. Then, total impedance to the point equals the square root of the square of the total resistance plus the square of the total reactance.

$$Z' = \sqrt{R^2 + X^2} \qquad (6)$$

$$\text{and } I_L = \frac{E_L}{Z} \qquad (7)$$

Ordinarily any drop in E_L is neglected, and E_L is taken as the voltage at the substation. A graphical method of calculating fault currents which provides sufficient accuracy and requires less labor has been developed and is acceptable to REA. It is outlined in the appendix beginning on page 73.

For line to ground voltage other than shown on the chart, multiply the current value obtained by the ratio of the actual voltage to the chart voltage.

D. Three Phase Fault Currents

1. Source Impedance
(a) Large System

$$Z_s = \frac{(E_L)^2 \ (\sqrt{3})}{(I_{3s}) \ (E_{s\,(L-L)})} \qquad (8)$$

If the line-to-line fault current on the supply side is the only value given,

$$Z_s = \frac{3E_L^{\ 2}}{2I_{s(L-L)} \ E_{s(L-L)}} \qquad (8a)$$

(see note under C-1-(a)

If the supply side positive sequence impedance, Z_1 , is given in ohms,

$$Z_s = 3Z_1 \left(\frac{E_L}{E_{s(L-L)}}\right)^2$$

(b) Small system or REA plant use direct axis transient reactance only, and apply formulae (2), (3) and (3a). Formula (4) is not required since a three-phase fault is equivalent to a balanced load and consequently no negative or zero sequence components are present.

For any tie line, use three times the positive sequence values only, and convert to REA voltage by multiplying by

$$\frac{E_L^2}{E_{s(L-L)}^2}$$

For any transformer in the tie line, use formula (5) directly.

2. Substation Impedance

Use formula (5) as before.

3. REA Line Impedance

Use resistance and reactance values under impedance to positive or negative sequence current for three-phase lines in Table II entitled "Impedance of REA Lines", page 42. It is only necessary to carry these values to the nearest 0.1 ohm.

With these values, proceed as before using formulas (6) and (7) or the graphical method outlined in the appendix.

E. Line-to-Line Fault Currents

1. Source Impedance

(a) Large System

$$Z_s = \frac{E_L^2 \sqrt{3}}{I_{s(L-L)} E_{s(L-L)}} \qquad (9)$$

If the three phase fault current on the supply side is the only one given,

$$Z_s = \frac{2E_L^2}{I_{3s}\, E_{s(L-L)}} \qquad (9a)$$

(see note under C-1-a)

If the supply side positive sequence impedance, Z_1, is given,

$$Z_s = 2\sqrt{3}\; Z_1 \left(\frac{E_L}{E_{s(L-L)}}\right)^2 \qquad (9b)$$

(b) Small system or REA plant.

For X_1 and X_2 use formulae (2) and (3) or (3a).

$$X_s = \frac{X_m \text{ (transient)} + X_m \text{ (negative sequence)}}{\sqrt{3}} \qquad (10)$$

Note: For any tie line, use $2\sqrt{3}$ times the positive sequence line values, and covert to REA voltage by multiplying by

$$\frac{E_L^2}{E_{s(L-L)}^2}$$

For any transformer in the tie line, multiply the impedance calculated by formula (5) by $\frac{2}{\sqrt{3}}$.

2. Substation

$$Z_t \text{ (ohms)} = \frac{Z_t \text{ (percent)} \quad (E_L)^2 (2)}{\text{(KVA per phase)} \quad (100{,}000)\sqrt{3}} \qquad (11)$$

3. Lines

Multiply impedance to positive or negative sequence currents, for three phase lines. Table II, by $\frac{2}{\sqrt{3}}$

Then $Z = \sqrt{R^2 + X^2}$

and $I_L = \frac{E_L}{Z}$ as in formulas (6) and (7), or use the graphical method

outlined in the appendix.

Except for systems supplied by small plants, the line-to-line fault current values will usually be $\frac{\sqrt{3}}{2}$ times the three phase fault

current values.

F. Minimum Fault Currents

In computing minimum fault values, simply use the minimum number of machines which will be in use in calculating the source impedance In addition, if the capacity of the plant is about the same as the demand on the project (i.e., the plant serves little or no other load besides the project), the positive sequence reactance used in formula (2) should be increased to allow for machine decrement. A value between the transient and the synchronous may be used, the exact figure depending on judgment. In most cases of this kind, REA has used a value of 40% for conservative results. For large sources of supply, the supply impedance is small and the decrement is therefore relatively unimportant.

For line-to-ground faults also add a value for effective fault resistance to the R component. This value is subject to judgment and may be from 0 to 1000 ohms, but 40 ohms is a conservative value, and is recommended. For line-to-line or three phase faults, neglect fault resistance.

G. Fault Current on Supply Side

A current on the load side of the substation of course causes a current to flow on the supply side. The following formulas apply for delta-wye banks only.

1. For line-to-ground fault

$$I_s = \frac{E_L}{E_{s(L-L)}} I_L^{*} \qquad (13)$$

2. For three phase fault

$$I_s = \frac{E_L \sqrt{3}}{E_s\ (L-L)} I_L \qquad (14)$$

3. For a line-to-line fault

$$I_s = \frac{2E_L}{E_{s(L-L)}} I_L \qquad (15)$$

*Note: (I_s is not necessarily the same in all three phases. The formulas give the maximum supply currents in any one phase.)

H. Map Plotting

After calculation of the short circuit currents, put the maximum and minimum values directly on the circuit diagram opposite each sectionalizing or other point. (See Example.)

CHAPTER III
SELECTION OF SECTIONALIZING DEVICES

Types of Sectionalizing Devices

Automatic and non-automatic devices can be used. Under automatic, the two general groups are (1) fused cut-outs and (2) reclosing breakers. (Automatic disconnecting devices now being developed may be considered a third group.) Non-automatic devices can be used in many cases where automatic operation is not practicable and consist of disconnect switches of all descriptions.

The fused cut-out may be single-, two-, or three-shot. In any case, the fuse link or links must be replaced after blowing. The reclosing breaker, on the other hand, will operate indefinitely without attention, unless a permanent fault, such as a conductor break occurs. The automatic diconnecting devices are designed to operate in conjunction with oil circuit reclosers to disconnect taps or sections of line when they become permanently faulted.

Of the automatic devices, fused cut-outs will generally be cheaper in first cost, but will be more expensive to maintain than other automatic devices. Single-shot cut-outs can be coordinated more easily than two or three-shot cut-outs, but on the other hand cause more outage time. Only a complete study of all factors can determine the best combination. Generally, at least two-shot cut-outs or automatic disconnecting devices should be placed on every important branch line. In cases where gapped transformers are used, reclosing breakers must be used to sectionalize the branch with these transformers and protect the remainder of the system against outages on lightning flashover. In other cases, it may be the judgment of the engineer that reclosing breakers will pay for themselves in reduced maintenance costs. Since temporary faults are usually very much in the majority, single-shot cut-outs will cause a great many unnecessary outages, whereas reclosing breakers will require the minimum attention. All other things being equal, it is preferable to spend available funds on reclosing devices of some kind, even if fewer devices are installed.

Switches or disconnecting cut-outs have a great deal of outage time by allowing the linemen to isolate the faulty section and restore service to the remainder of the system. It is suggested that these be installed so that the lines can be disconnected at least every five miles.

Selection of Fuse Sizes

1. Data Necessary

   If fuses are to be used for coordination purposes, it is absolutely essential that only one make of fuse link be used throughout the lines on the load side of the substation. The fuse on the supply side may, and generally will, be different.

   The first step is to obtain curves and tables of the fuse links to be used on the lines. The curves necessary are (1) the total clearing time curves and (2) minimum melting time curves. Curves (2) may not be

necessary if the table mentioned below (pages 59 & 60)is obtained. These curves show current plotted against time for various size fuses.

(1) Total Clearing time curves: These curves are available from all fuse manufacturers and represent, for each fuse size, the total time taken for the fuse to clear the circuit for various fault currents. (See page 62).

(2) Minimum melting time curves: These curves indicate the minimum time for the fuse to melt. From the melting time curves, "damaging" time curves can be found by applying a factor of safety recommended by the manufacturer. If such a factor of safety is not obtainable, it is suggested that the "damaging" time curve be made by taking 75% of the melting time (in seconds) of a particular size for each current. For example, in Fig. 1 below, if curve (1) represents the melting time characteristic for a given size, curve (2) will represent the "damaging" time, with a factor of safety of 25%. Other factors of safety can similarly be used.

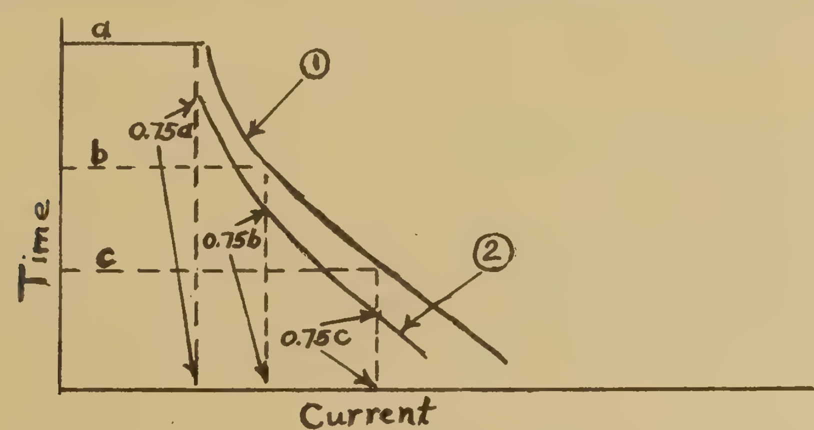


Figure 1.

These curves represent for each size the time in which a fuse will be damaged or rendered unfit for further use by various fault currents.

If fusing tables, such as on pages 59 & 60 are obtained, it is only necessary to obtain "damaging" time curves for the fuse on the supply side of the substation. If such tables are not available, "damaging" time curves must also be made for the fuses on the load side. Total clearing time curves should be obtained for fuses on the load (REA) side in any case.

Some manufacturers make a fuse filled with powder which, it is said, aids in extinguishing the arc. In such cases, the "melting" time curve is generally called a "Heating" time curve.

2. Substation Protection:

The next step is to select the fuse at the substation so as to protect the substation transformers against any fault current likely to occur.

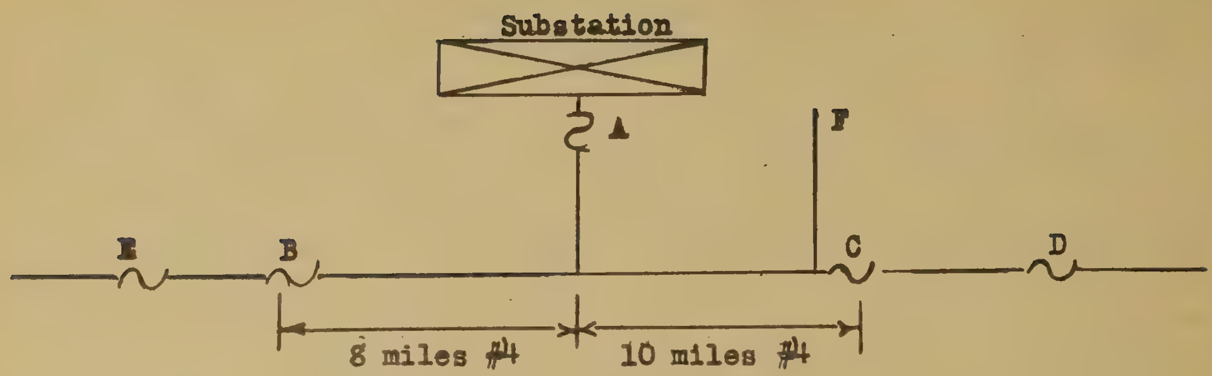


Figure 2.

Each fused device may be thought of as being in charge or control of all the line on the load side of the device up to the next device in series with it, in the direction away from the substation.

In Figure 2, the fuses at A must operate for fault current in its controlled section ABCF before the substation transformers are damaged. Fuse B controls section EB, and fuse C controls section CD.

Due to the relative slopes of the transformer damage time curve and the fuse clearing time curve, the minimum current in the section under control is the one to be checked. (See Plate "F", page 65). If the fuse protects the transformer for the minimum fault current, the fuse will also protect for any greater current. This is not necessarily true for circuit breakers.

Since point C is further from the substation than point B, in Figure 2, this means that with minimum fault current at point C, fuses at A must protect the substation against damage. If there is an unfused branch CF, with a minimum fault current at F less than at C, then the minimum value at F should be used. The fuses at C are assumed to take care of faults beyond C. This minimum current may be either a line-to-ground, three phase, or line-to-line fault current.

Curve sheets 1A and 1B, pages 44 and 45, show the A. S. A. proposed curves for permissible short time overloads of transformers. Plot the curve of the particular substation transformer size used on the project, on the sheet of the total clearing time curves of the fuse links used. Now on the current scale of these curves, find the minimum current in the controlled section. Select a tentative fuse size rated at about double the current capacity of the transformer bank.

For a single shot fuse at A for the above minimum current, if the total clearing time of the fuse is less than for damage of the transformer to occur, the fuse is safe. For a two-shot fuse, multiply the total clearing time of the fuse by two, and compare with the failure time of the transformers for the same current. If the total fuse time is lower, the fuse is safe. If higher, a lower rating must be used. For a three-shot fuse, multiply the clearing time by three and proceed as above. If the first shot, or the first two shots, are tentatively to be fused at a lower value than the last, simply add the total clearing times of all two or three fuses for the particular minimum current and compare with the

transformer damage time as before. The total clearing time of the substation fuses must be less than the time taken to damage the transformer on minimum fault current in the controlled section. This process neglects any cooling due to time-delay between shots, and is therefore conservative. There should also be sufficient minimum current to blow the substation fuse in a reasonable time; that is, the fuse rating should be selected so that the minimum current does not lie on the upper, or flat part of the fuse curve, where time values change considerably with slight variations in fault current.

In order to provide margin for sectionalizing on the remainder of the project, the fuses at the substation should be made as large as possible, while still maintaining safe protection of the substation, keeping other factors in mind. If the substation fuse ratings are considered too small, larger ratings can often be selected by moving the next sectionalizing device (C in Figure 2) closer to the substation, thus increasing the minimum current in the controlled section.

It is practically impossible to protect the substation transformers against overload by the use of fuses, and still obtain the necessary number of sectionalizing steps on a project. A thermal indicator, either visual or with alarm system, can be used to indicate long-time overloads.

Next, a check must be made to see that the substation fuse size so selected coordinates with the fuse or breaker on the supply side of the transformer. To obtain the currents on the supply side for faults on the load side use formulas (13), (14) and (15). The coordination between the load side fuse and the supply side fuse or breaker should be checked for the maximum fault current right at the substation on the load (REA) side, and for the three different types of faults. The following discussion outlines the procedure for any one of the three fault types.

Determine the total clearing time of the load side fuse at the maximum I_L (right at the REA side of the substation). If two-shot, multiply this time by 2, and if three-shot, multiply by 3. If different fuse sizes are used, add the total clearing times of the fuses in all shots. Compare this time with the damaging time (See page 17) of the tentative fuse selected for the supply side at the I_s determined by formulas (13), (14) or (15). If the time of the REA side fuses is less in all cases, the coordination is probably satisfactory for all three types of faults. Since the characteristic of the supply side fuse link is different from that of the load side fuse link, coordination at maximum current may not necessarily indicate such coordination over the entire range of possible fault currents, although this is the usual case. To make such coordination certain, the complete characteristics can be plotted and compared. (See Plate "F", example.)

Since the current conversion formulas indicate a much greater relative difference between load and supply currents for a line-to-line fault than for the other two types, the line-to-line fault current will usually be found to be the criterion insofar as coordination between supply and load side devices is concerned.

It will often be found that the supply side fuse or breaker setting is so limited in rating that it is not possible to obtain coordination between the load side and supply side devices for all three types of faults, and it is not practicable to reduce the rating of the load side fuse. In this case,

a less restrictive fault type can be used, and it is assumed that the supply fuse will blow for the occasional times that other types of faults occur. Coordination should be assured for line-to-ground faults, as these are the most numerous, and if possible, for the other types.

Close cooperation with the power supply organization must be obtained in selecting the supply side fuse. No fuse should be selected without the supply organization's approval. If the substation is supplied by an REA plant, the supply side fuses must naturally be coordinated with any sectionalizing devices in the plant.

No account is taken above of the cooling effect due to time delay between shots of the cut-out on the REA (load) side. No accurate method, short of actual test, can accomplish this. Judgment may be used on the part of the engineer in borderline cases. If there is a breaker on the supply side, the time of the load side fuses, as determined above, should be less than the first opening time of the breaker for the range of fault currents encountered. The breaker time or relay time can generally be obtained from the power supply organization.

The size of the fuses at the substation are now definitely established by the above procedure.

3. Line Fusing:

Now proceed to the last sectionalizing point of the system. On a distribution transformer failure, the fuse at this point should withstand the maximum short circuit current at this point while the transformer fuse blows. In other words, the last sectionalizing fuse should coordinate with the transformer cut-out fuse immediately beyond it. (For exceptions, read remainder of text.) The following table is recommended by REA for conventional distribution transformers using standard universal cable type fuse links.

Table

Transformer rating, KVA	$1\frac{1}{2}$	3	5	$7\frac{1}{2}$	10
Transformer Fuse Rating, Amps	2	2	3	5	5

Fuse links having high surge current capacity combined with low melting current rating have been developed and may be used in the primaries of distribution transformers. The size of these special fuse links should be in accordance with the manufacturers recommendations and will, in general, be smaller than those listed in the above table.

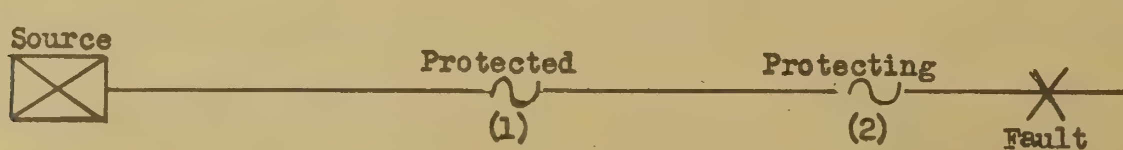


Figure 3.

Figure 3 illustrates the general principle of coordination. Fuse (1) is called the protected fuse, and fuse (2) the protecting fuse. For perfect coordination, fuse (2) must clear the circuit on a fault anywhere beyond it (in the section controlled by fuse (2)) before fuse (1) is damaged. If (2) is a two or three-shot, all the fuse links should clear before any fuse link at point 1 is damaged. For this reason it is more difficult to coordinate two or three-shot fuses in the order named than single-shots.

Due to the inherent characteristics of fuses, the maximum current in the section controlled by fuse (2) is the determining current, which means the maximum fault current at point (2) should be used in coordinating the fuse links. This rule holds good only so long as the fuse links are of the same type. If links of different type of manufacture are used, coordination must be checked over the entire range of fault currents in the section controlled by fuse (2). (For example, load and power fuses at the substation).

In Figure 3, point (1) may represent the last line fuse on the system and point (2) the transformer fuse immediately beyond it.

Most fuse link manufacturers have now published tables which make such coordination very simple (see example for sample table, page 59.) The values in the left hand column are the protecting fuse ratings (2) and the values across the top, the protected fuse ratings (1). The values in the table then show for what short circuit currents fuse (1) will be protected by fuse (2). These are maximum values; in other words, for any short circuit current greater than that shown, fuse (1) will be damaged, and hence a larger size must be used, or the position must be changed. The fault is assumed to occur just beyond position (2). For example, assume the maximum fault current at the last sectionalizing point is 40 amperes, and the distribution transformer cut-out fuse is rated 2 amperes. It can be seen from the sample table that a 5 ampere fuse will be "protected", by a 2 ampere fuse up to 60 amperes, and hence is satisfactory. A 3 ampere line sectionalizing fuse is not satisfactory since no value is given in the table for a 2-3 combination. If the fault current were greater than 60 amperes, it would be necessary to go to an 8 ampere fuse on the line.

Now a check must be made to see that the 5 ampere fuse is not too large to blow under minimum fault current at the extreme end of the line. This is done by making sure that the minimum fault current is greater than the current to blow the fuse in 100 seconds. This can be obtained from the total clearing time curves of the fuse link used.

This check is important, and should always be made. Furthermore, in cases of long systems connected to small plants and substations, this check should be made for every line fuse on the system; i.e., each must blow on the minimum fault current at the next sectionalizing point, in other words, at the end of its controlled section in a reasonable time. Ordinarily, the above checks are necessary at only one or two points, but if there is any reasonable doubt as to a fuse blowing, a check should be made in each case.

Assuming that the 5 ampere fuse is safe, this rating is now definite and the size of the next fuse toward the substation must be determined. The 5 ampere fuse now becomes the "protecting" fuse, and the next one toward the substation, the "protected" fuse. Here the same procedure is repeated

as before. The protected fuse must withstand the maximum fault current at the position of the 5 ampere (protecting) fuse during the time the 5 ampere fuse is blowing. Assume this current is 60 amperes. It can be seen from the table that a 5 ampere fuse (left column) will protect a 10 ampere fuse up to 60 amperes. Hence, a 10 ampere fuse is satisfactory at the next point.

If the ampere fuse is two-shot, however, it will be necessary to go to a 15 ampere fuse at the next point, as the table shows coordination only up to 25 amperes for a two-shot 5 ampere fuse with a 10 ampere fuse. If the 5 ampere fuse is used in a two-shot cutout, the table shows a 15 ampere fuse in the next step will be satisfactory. Assuming a two-shot fuse, the 15 ampere size is selected, and now becomes the protecting position, and the next fuse in line becomes the "protected" position, and the process is repeated for the maximum fault current at the 15 ampere position.

This method of selection is continued until the substation fuse is reached. The size of this fuse has already been selected from other considerations, and the next fuse farther out must coordinate with the substation fuses. If the substation fuses are not large enough to withstand the maximum fault current at the next sectionalizing point farther out while the fuses at this point are blowing, then the size of the fuses at this sectionalizing point must be reduced. This may in turn necessitate any one of the following steps:

(1) Reduction of all fuse sizes from the substation to the ends of the system.

(2) Replacement of some three-shot fuses by two-shots, and some two-shots by single-shots.

(3) Elimination of one or more automatic sectionalizing devices, replacing with non-automatic switches, if desired.

Whenever a branch line taps off the main line, and is fused, this fuse must be coordinated with the next fuse in the direction of the substation as before. Every line fuse should, if possible, coordinate with the primary transformer fuse next to it.

When internally fused transformers are used, it is usually difficult, if not impossible, to coordinate the line fuses near the ends of the lines with the internal transformer fuse, and still provide sufficient sectionalizing points on the system. In most cases, such transformers have secondary breakers, which render the situation less serious. However, in some cases, an interruption of service may be necessary until the damaged transformer is located.

Fuse curves can also be used for coordination in place of the tables. The method of coordination is to make sure that the total clearing time of the protecting link, point (2), is less than the damaging time of the protected link, point (1), for the maximum short circuit current at the position of the protecting link. For two- or three-shot fuses, the total clearing time of

the protecting link must be multiplied by 2 or 3, if the reclosings are instantaneous, or by some lesser factors if there is time delay in reclosing. The tables, which are generally compiled from actual tests, take all these factors into consideration, and are hence much more simple and accurate.

4. Expediencies:

In some cases, where an insufficient number of sectionalizing devices can be used, various methods can be employed to coordinate additional devices. For example, a single-shot 5 ampere fuse might have been used in the first position above instead of a two-shot. Then, a two-shot 5 or 8 ampere fuse could be used in the next position, and possibly a three-shot 5 or 8 ampere fuse in the next position toward the substation. By this means an additional device or two in series may often be added. This is purely an expediency, however, and should be used only as a last resort. Linemen must be instructed to replace all fuses at all of the two or three positions upon fault beyond the last one, as all fuses are likely to be damaged. Sometimes, if perfect coordination of two or three shot fuses cannot be obtained, the best possible combination is recommended, with instructions to the project to not only replace the blown fuse links but also the first fuse link in the preceding cut-out toward the substation, even though this fuse link appears to be undamaged. In fact, the latter rule is a good one in any case.

Often some gain can be made by using 2 or 3 shot cut-outs with time delay reclosing. Such time delay allows the preceding fuse to cool off between reclosures, so that fuse sizes may be closer together than normally. The coordination of such devices must be obtained from the manufacturer, or the decrease in fuse time gained by such cooling action must be estimated.

Another aid in sectionalizing is to use a three-shot at the substation with the first cartridge fused light, and the others according to needs for coordination. Temporary trouble on the lines blows the first fuse, which is easily replaced, as it is generally near the office and hence saves a trip by the linemen. The first cartridge fuse must, of course, be large enough to carry the load current.

Another method is to eliminate the distribution transformer cut-out fuse from consideration. In other words, the last sectionalizing fuse is made about the same size as the transformer fuse, or at times, even smaller, and is allowed to blow when the transformer fails. The method of operation when this occurs is to short out the line fuse with a jumper on a hot stick, thus burning out the transformer fuse or internal link and clearing the line. In this case, the next line sectionalizing device toward the substation must be made large enough to hold in while the transformer fuse blows. This method is generally more applicable with internally fused transformers, if the internal fuse rating is high.

Where the above method of shorting out the line sectionalizing device to blow the transformer's weak link is used, a check should be made to see that there is sufficient minimum current to cause the internal fuse to melt.

C. Coordination of Breakers and Reclosers

Breakers for REA lines may be placed in one of two classes: (A) magnetically operated; (b) operated by relay.

1. Magnetically Operated Breakers (opened by means of a coil)

Magnetically operated breakers are not subject to thermal limitations and hence breakers of this type reclosing two or more times may be coordinated with each other by comparing the first opening curves of the protected and protecting breakers. The time of opening of the protecting breaker must be less than the time of opening of the protected breaker for all ranges of fault currents which are anticipated. The sizes of automatic reclosing breakers of any one make and type are designed to coordinate with each other when the protecting breaker is one size smaller than the protected breaker. Since some makes of single pole reclosing breakers have very short opening time and depend on differences in their reclosing time for coordination of different sizes, considerable margin in first opening time must be allowed when it is necessary to coordinate fast opening breakers of different makes with each other. Much more satisfactory results can be expected if one make of fast opening breaker is not used in series with other makes of fast opening breakers. It is possible, however, to coordinate fast opening breakers of one make with reclosing breakers of other makes having time-delay on the last two operations.

It is necessary that there is sufficient minimum current at the end of each controlled section to operate the controlling breaker. For example in figure 4 there must be sufficient minimum current at the end of the section controlled by breaker (2) to provide pickup for breaker (2). The same applies to breaker (1). Furthermore, the control zones should overlap sufficiently so that there is no possibility of any section being unprotected. This can be accomplished by allowing ample margin between the minimum breaker pickup and the minimum current in the controlled section. The manufacturer supplies data in regard to minimum pickup. This check is particularly important for this type of breaker. (This includes breakers such as the G. E. FP-119, Kyle A, Kyle H, Westinghouse AR-1, and Kearney.)

The protection afforded to the substation transformers by a breaker can be checked by comparing the total opening time of the breaker (adding all operations) with the damage time of the transformers for the complete range of fault currents in the section controlled by the substation breakers, preferably by plotting comparative curves. It is not sufficient to check only the minimum value. It is sometimes desirable to provide additional protection for the substation transformers for currents below the minimum trip current of the breaker. This may be done by checking the protection given by the supply side fuse, or if this is inadequate, a fuse may be installed between the breaker and the substation which will have a time-current characteristic greater than that of the breaker for the breaker operating range, but which will give additional protection for fault currents below which the breaker will not operate.

The above procedure may be unnecessary where the fault currents are more than ample to operate the breaker, but does offer a second line of defense in borderline cases. It is not possible, however, to give long time overload protection with such overcurrent devices.

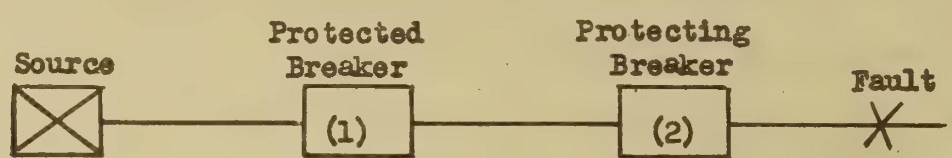


Figure 4.

Reclosing breakers can also be coordinated in some cases by varying the number of reclosings. For example, the protecting breaker can be made for two reclosures, and the protected breaker for three, etc. This method is not generally recommended, but may be used in occasional cases.

Breakers of all types can also be coordinated with fuses by comparing the proper characteristics. Magnetic breakers generally have an entirely different time-current characteristic than fuses, and hence are more difficult to coordinate than fuses alone.

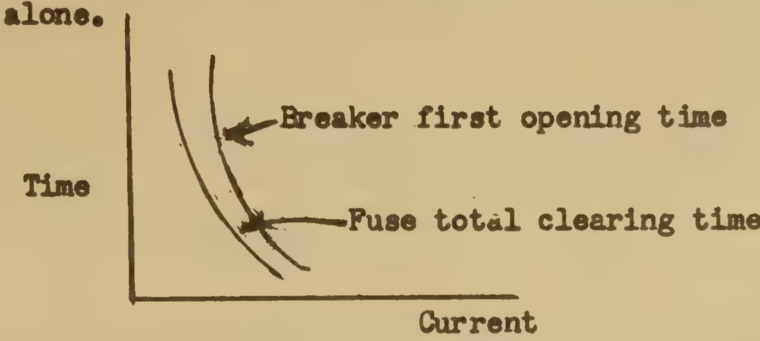


Fig. 5

If the fuse is protecting the breaker, (such as the fusing on individual service transformers), the total clearing time fuse curve should lie to the left of the first opening time curve of the breaker for the range of fault currents considered if the breaker has high speed openings for all operations. For breakers with time delay on some or all of the openings a fuse rating may be selected such that the breaker will successively trip once or twice without blowing the fuse, but the fuse will blow before the breaker makes its final opening.

This type of coordination is particularly applicable when there is high speed opening on the first one or two breaker operations and time delay on the succeeding operations. In this case the fuse damage time curve should lie to the right of the initial high speed breaker opening or openings (allowance being made for cumulative heating of the fuse if there is more than one such successive opening), while the total clearing time of the fuse should lie to the left of the breaker final opening curve, both for the range of fault currents considered. See Fig. 6

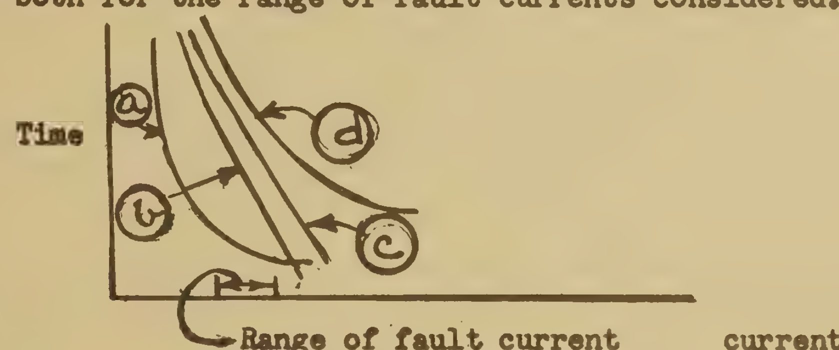


Fig. 6

a. First opening of breaker or cumulative effect of first openings
b. Fuse damage time
c. Fuse total clearing time
d. Breaker final opening time

With fast opening breakers of small rating it is difficult to install sectionalizing or branch line fuses beyond the breaker such that the fuse will not be damaged on first opening but will blow before final lockout. However, it is possible to shunt the breaker with a fuse after lockout, so that the branch or section fuse (or transformer fuse) will blow and remove the faulty device. The shunt fuse is then removed and the breaker reclosed. (See also page 23). The shunting fuse rating should be such that the fuses beyond will clear before the shunt fuse is damaged, but the breaker or fuse toward the substation will not lockout or be damaged. Use tables prepared by the manufacturer, or compare curves. This shunt fuse may be used in a permanently installed cut-out or in a jumper carried on the truck. In any case, such shunting schemes should be considered temporary until breakers with different characteristics can be obtained. With opening time delay breakers, sectionalizing points and branches can be fused, as explained above, such that the reclosing breaker operates on temporary faults (about 95% of the total faults on R.E.A. systems) with the fuse automatically disconnecting branches or sections for permanent faults.

A new automatic mechanical disconnecting device is also being brought out which is designed to accomplish the purpose of disconnecting branches and sections beyond breakers, and which does not depend upon the opening time of the breaker.

If the breaker is protecting a fuse, Fig. 7 applies

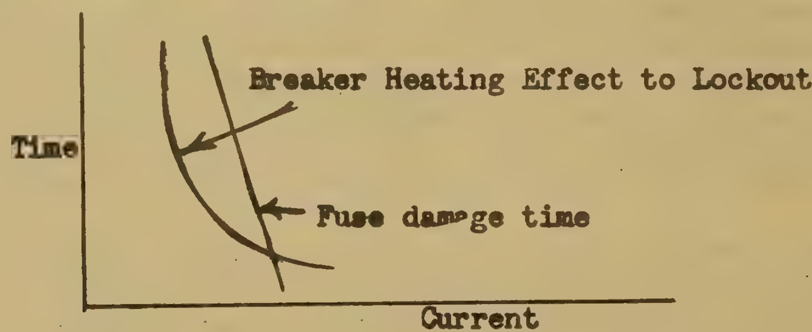


Fig. 7

The damaging time of the fuse for the range of short circuit currents expected must be greater than the opening time of the breaker, making allowances for cumulative heating of the fuse during repeated consecutive operations of the breaker. Most manufacturers will furnish these data. If not, the engineer will have to use his judgement, aided by experience with other installations. Fig. 7 applies where a breaker is used on the load side of the substation, and a fuse on the supply side. The current passing through the supply side fuse must, of course, be obtained by correcting by the ratio of transformation as indicated above.

If automatic disconnecting devices are used they must be used on the load side of oil circuit reclosers and be coordinated with them. This requires that the disconnecting devices operate on the minimum fault current in the section and will not be damaged by the maximum fault current. The current carrying capacity of the disconnecting devices must be adequate for the maximum load current.

2. <u>Relay-Operated Breakers</u>

Breakers controlled by relays are used primarily in power plants supplying the project and occasionally at the substation. The usual type is the over-current relay. In coordinating the relay, the time-current characteristics of the relay must be compared with the characteristics of the next device in series with it.

There are two general types of overcurrent relays in use: the solenoid plunger-type with and without time delay, and the induction type. For coordination purposes, it is preferable to have a relay with time-delay tripping as otherwise the relay must be set to a very high current value to avoid improper operation. The solenoid plunger-type is usually used in small plants, and usually carries the total current. There is a calibrated set-screw or other device on the relay which determines its tripping current. The induction type, however, is almost always connected to the main circuit by means of a current transformer. In order to properly set the relay, it is therefore necessary to know the current transformer ratio.

The induction relay has two methods of adjustment: (1) by changing the current tap setting, and (2) by changing the time lever setting. The current tap setting determines the minimum "pickup" current point, while the time lever setting determines the amount of time delay in the tripping. The tripping characteristics are usually stamped on the face of the relay.

For example, suppose the current transformer ratio is 200 to 5 and the tap setting on the relay is 4 amperes. This means that the relay 100 percent point is $\frac{200}{5}(4) =$ 160 amperes. The minimum trip point can then be determined from the characteristic time-current curve of the relay. The relay field is too broad to cover in a short paper. Suffice to say that there are a large number of different types of relays. The general method in each case is to compare time-current characteristics for coordination purposes.

For breakers operated by relays the total opening time of the breaker is the relay time plus the opening time of the breaker. The latter may be comparatively small and may be neglected in some cases, but it is well to check this.

In protecting a substation transformer with a breaker of any kind, the entire relay plus breaker opening time curve should be plotted and compared with the transformer "damage" curve, as it is <u>not</u> sufficient to check the breaker for only minimum current in the controlled section. If the breaker is reclosing, the cumulative heating of the substation transformer must be taken into account for all reclosings to lockout.

In coordinating a multi-shot device beyond a relay-operated breaker with the relay, it must be remembered that the relay induction disk will rotate forward for each shot of the device, and the total times of the shots must be less than the relay contact closing time. If the time-delay between shots is considerable, the disk will, of course, return partly or completely to its original position. The most practical method of determining border-line settings is by means of field tests, although preliminary settings can be made by calculation and judgement.

On some systems, a reclosing substation breaker is used, with relay control such that the breaker opens practically instantaneously the first time, recloses, and opens with time delay two subsequent times if the fault persists. With this device, fuses are used for sectionalizing and branch lines and fuse sizes are selected such that the fuse stays in for the first breaker opening, but is blown by the subsequent time delay opening. Fuse and relay settings are readily determined by comparing time-current characteristics. (See also above)

The advantage of any type of reclosing breaker over the fused cut-out is that the breaker will automatically reclose for temporary faults, while the fused cut-out must be visited and fuses replaced. Surveys on REA systems have shown that over 95% of faults in the spring and summer months are temporary.

D. Current-Interrupting and Carrying Capacity

It is now necessary to see if the cut-outs or breakers are of sufficient capacity to interrupt the maximum fault current to be expected through each device. Cut-outs for 7200/12500-volt REA lines are specified to interrupt current as follows:

50 ampere rating - 1,200 amps. 100 ampere rating - 3,000 amps.

The interrupting rating of a breaker is usually stamped on the name plate or given in the data sheet. The interrupting check on a breaker is very important and must be made in each case. The fuse or other device on the supply side of the substation must be checked to see that it has sufficient capacity to interrupt the maximum fault current on the supply side. The manufacturer will furnish interrupting ratings.

Fuse links and breakers are also rated according to the continuous current carrying capacity. It is necessary to check the maximum anticipated load current passing through each fuse or breaker to see that it can safely and continuously carry that current. These loads have usually been determined in a previous voltage regulation study or if they have not, curve sheet 3 may be used in estimating the maximum load current. The safe current carrying capacity of a fuse is simply the value of the fuse size for 100% rated links (i.e.,5 amps.,etc.). It is also necessary to check the cut-out rating. For example,any fuse over a 50 ampere rating must be used in a 100 ampere cut-out. (Some manufacturers have special fuse ratings to avoid this.) The rating of breakers and disconnecting devices is specified on the name plate of the device.

To facilitate the work, the current carrying and interrupting ratings can be checked at the same time the coordination work is done, so that a fuse size or breaker selected for coordination can be immediately checked for proper current rating.

CHAPTER IV
RE-CHECKING AND COMPLETION OF STUDY

A. Sectionalizing in General

In making studies based on the use of different types of devices, a chart of the time current characteristics is usually helpful as it shows the coordination visually. Log-log paper is the best. It is necessary to transfer all currents to a common base (usually 7200 volts) to show all relationships. The substation transformer damage time curve should also be shown. (See example, Plates "F" and "G", pages 81 and 82.)

A study of this type should always be made before purchasing additional sectionalizing devices, particularly expensive devices such as breakers.

In many cases, it may be impossible to coordinate the desired number of automatic sectionalizing devices. In these cases, manually operated switches of one sort or another are effective. For the three-phase lines, it may be preferable to install a three-pole switch, operated from the ground. On single phase lines inexpensive blade switches, hot line clamps, or disconnecting cut-outs may be used. If enough of these switches or disconnecting cut-outs are available, it is suggested that they be installed so that the power lines may be opened about every five miles.

Where there are a number of three-phase motors on a project, either three-pole breakers should be used on the lines or each motor should be equipped with over-current protection on at least two phases of the starter, in order to prevent motor burn-up. In addition, the transformer bank should be connected with floating neutral (see Operations Memorandum 19-2). When using single pole breakers or fused cut-outs on multi phase lines which also serve three phase transformer banks, the system personnel should recognize that as much as half normal line to ground voltage may exist on an opened phase, and it should therefore be treated as HOT.

Adequate sectionalizing may very often raise a question as to the length of lines to run from a single substation. With present devices, it is difficult to sectionalize properly with extremely long lines. Such considerations may point to the use of smaller units of line, fed from two or more substations, rather than large projects fed from a single source. Such a question is, of course, tied up with the rate, power supply and voltage regulation questions, but sectionalizing problems may require serious consideration of alternate possibilities of power source.

B. Completion of Work and Instructions to Project

After making all studies and selecting fuse and breaker sizes, a complete circuit diagram of the project should be prepared in accordance with Engineering Memorandum 154, with the selected apparatus and sizes clearly indicated. Several copies should be left with the project management and a copy sent to REA. Copies of all original data and calculations should also be left with the project.

The project should instruct its linemen to always replace a fuse by a link of the proper size and make. Linemen should have a copy of the circuit diagram and an ample stock of all sizes of links.

It should be understood that a theoretical study will not always give perfect results in practice. It may be necessary to change fuse link sizes, relay settings or move breakers, as dictated by experience. It is very dangerous, however, to increase fuse or breaker sizes just to keep from making trips. A change in fuse size, or a breaker replacement or adjustment, should be made only by authorization of the superintendent or manager, after careful consideration and with conclusive evidence that the presently used sizes do not coordinate properly. Such changes should then be made on the circuit diagram.

Fuse links may often be at the seat of difficulties on a project, and it may be necessary to try a different kind. If this is done, a re-study, using the new brand, should be made. Different makes of fuse links must not be mixed on lines receiving power from the same substation. If any change is made, it should be complete.

WHEN ANY CHANGES ARE MADE TO THE SYSTEM, SUCH AS ADDITIONS OR REVISIONS OF LINE OR INCREASE IN SIZE OF THE SUBSTATION, A SUPPLEMENTARY STUDY MUST BE MADE TO KEEP THE SECTIONALIZING PROGRAM UP TO DATE AND TO SEE THAT RATINGS OF DEVICES ARE STILL ADEQUATE. THE SYSTEM MANAGEMENT MUST ALSO CAREFULLY MAKE PERIODIC CHECKS OF PEAK LOADS ON SECTIONALIZING DEVICES, TO MAKE SURE THAT OVERLOADS DO NOT OCCUR WITH LOAD GROWTH.

CHAPTER V
PROTECTION OF DISTRIBUTION TRANSFORMERS

Some of the points involving distribution transformer protection have already been sketchily outlined. This section will give a general outline for more scientific methods of calculating proper size apparatus for such protection.

Transformers may be protected by devices on the primary, the secondary or on both sides. Various devices, such as fuses or breakers, either internal or external may be used. Some manufacturers make transformers with secondary breakers as an integral part of the transformer, and in such cases, the device is presumed to give adequate protection from faults or overloads on the secondary side. This discussion will not concern itself with such cases, as the setting of the breaker is fixed by the manufacturer. The service length, however, is the limiting factor in installations of this kind.

A. Fused Protection

1. Primary side

Ordinarily, fuses can protect only against fault conditions on the secondary side. If the fuse is set so as to give protection against overload, it will be of such a low rating as to give too many false operations from other causes such as lightning, vibration, birds, or improper coordination with fuse and breaker ratings on the consumer's premises.

Curve sheets 2A and 2B, pages 46 and 47, give the fault current on the primary of the transformer for different size units and for different lengths of service line. These curves are based on a transformer impedance of 3.5%, which is generally greater than the impedance of those now in use, and hence the curves are conservative. Fault resistance and primary line impedance have not been considered in the curves of sheets 2A and 2B. Since both the transformer damage curves in sheet 1A and the 3.5% impedance value used are conservative, it is probably not necessary to add further safety factors for these other impedances. In fact, in some cases, the 3.5% impedance value may be somewhat too great, in which case the engineer can make up other curves based on a lower impedance value. For transformer impedances greater than 3.5%, the curves should be used with discretion.

If the primary fuse is to give protection for secondary faults, it must be selected so that it will clear the circuit on the minimum possible fault current before the transformer is damaged. It can be seen from curve sheets 2A and 2B that insofar as the primary fault current is concerned, a 120 volt secondary fault on a three-wire 120/240 volt service gives the least primary fault current for any length service.

Suppose it is assumed that a 2-ampere Super #XX-1D fuse is to be used to protect a 5 kva 7200-120/240-volt transformer. The next question becomes: "What is the maximum length of service for which this fuse will give adequate protection to the transformer?"

Curve sheet 1A, page 44, gives the A.S.A. standard for permissible emergency short time transformer overloads. As the transformer is connected for three-wire service, each secondary winding is rated for only half capacity, and the primary rating, insofar as damage to the transformer is concerned on a 120-volt fault, is only half the 5 kva rating. Hence the primary current values on the damage curve are only half those of the regular 5 kva damage curve for the same time values. For a two-wire secondary (secondary coils in parallel) the full primary damage curve would be used. On plate "B", page 62, is plotted a short section of the damage curve for a 120-volt fault on a 5 kva three-wire transformer.

It can be seen that it intersects the 2 ampere fuse curve at 13.3 seconds and 3.85 amperes. This primary current is 5.55 times the normal primary rating whereas the secondary current is 11.1 times normal. In other words, for a primary current of less than 5.55 times normal for a 120-volt fault on a three-wire service, the transformer will be damaged before the fuse clears the circuit. Turning now to curve sheet 2A we see that at 5.55 times normal primary current or 11.1 times normal secondary current for a 120-volt fault on a three-wire service, the service distance for a 5 kva 3.5% impedance transformer is 295 feet for a #8 service, 450 feet for a #6 service and 710 feet for a #4 service. Any distances greater than these would be dangerous.

For two-wire services, curve sheet 2B, page 47, is used, and the damage curve of the <u>total</u> transformer rating is applied. For example, suppose the question is as follows: "Will a two-ampere Super #XX-1D fuse protect a $1\frac{1}{2}$ kva transformer on a 200-foot 2-wire #6 service?"

From curve sheet 2B we see that a 200-foot, 2-wire #6 service gives 19.15 times normal current on a $1\frac{1}{2}$ kva transformer or 3.99 amperes on a 7200 volt base. From curve sheet 1A the transformer will be damaged by 3.99 amperes in 5.9 seconds. From Plate "B" the 2-ampere fuse will clear the circuit in 10 seconds on a fault of 3.99 amperes and hence will not protect the transformer.

2. Secondary Side

For secondary protection, the <u>minimum</u> fault current through the fuse may be either on a 120-volt or a 240-volt fault, depending on the service distance.

Suppose the question is as follows: "For what service length will a 50-ampere Super #Y2-M2 secondary fuse protect a $1\frac{1}{2}$ kva transformer on a #6 three-wire service?"

From Plate "E", page 64, showing the time-current characteristics of the Super #Y2-M2 fuse link, we see that the damage curve of the $1\frac{1}{2}$ kva three-wire transformer (Plotted on the basis of secondary current) crosses the 50-ampere fuse curve at 107 amperes or 17.15 times normal. For any values less than this, the transformer will be damaged before the fuse clears. Going now to curve sheet 2A, we find that for a

120-volt fault, an 800-foot service gives 17.15 times normal secondary current, while for a 240-volt fault, a 1085-foot service gives the same value. Since the 800-foot service is the smaller, this is the limiting value, and is used. If we selected some larger fuse, the 240-volt fault might cause the limiting fault current instead of the 120-volt fault.

Suppose the problem was as follows: "Will a 60-ampere Super #Y2-M2 secondary fuse link protect a 1½ kva three-wire transformer with a service length of 300 feet of #8 conductor?"

From curve sheet 2A, we see that a 240-volt fault gives 22.4 times normal secondary current, while a 120-volt fault gives 23 times normal. These are 140 amperes secondary or 4.67 amperes primary, and 144 amperes secondary or 2.3 amperes primary respectively. Since the 240-volt fault gives the lower secondary current, we test with it. On curve sheet 1A at 22.4 times normal current (4.67 amperes primary), the time for the transformer damage is 4.7 seconds. At 22.4 times normal (140 amperes on the secondary) on Plate "E" the 60-ampere fuse will blow in 4.9 seconds. Hence the 60 ampere fuse is not safe. A 50 ampere super #Y2-M2 secondary fuse will clear in 2.6 seconds and hence would be safe.

On any particular job, the engineer, knowing the kind and size of secondary fuse to be used, can easily make up tables of maximum service length distances for safe protection. Such tables can then be given as instructions to the stakers. Similar tables can also be made for primary protection.

Technical Standards Bulletin #10, titled "Transformer Problems", gives tables showing protection afforded by various makes and ratings of fuses for transformer sizes and service lengths ordinarily encountered on REA systems. For uses designed or brought out since the date of Bulletin #10, these tables should not be used.

3. Primary and Secondary Protection

Where the transformer has both primary and secondary protection, the secondary device is assumed to take care of secondary faults, while the primary fuse is only for the purpose of removing the transformer from the line in event of failure.

B. Breaker Protection

Breaker sizes or service line lengths can be calculated in much the same manner as fuses. It is only necessary to have the tripping characteristics of the breaker instead of the clearing characteristics of the fuse.

C. Coordination of Secondary Fuse with House Fuse or Breaker, and with the Primary Transformer Fuse

It is necessary not only to select the proper fuse or breaker to protect the transformer *if* secondary protection is desired, but this fuse must be coordinated with the fuse or breaker in the house, and with the primary fuse, either internal or external, in the transformer. The methods used

are exactly similar to those given above for sectionalizing. The clearing time of the house fuse or breaker must be <u>less</u> than the damaging time of the secondary fuse or breaker on the <u>maximum</u> fault current at the house fuse. The secondary fuse or breaker must clear the circuit in less time than taken to damage the internal or external primary fuse on the maximum fault current at the transformer terminals.

Curve sheets 2A and 2B will give the secondary fault currents. If the transformer impedance is materially less than 3.5%, this value should be increased. Characteristic time-current curves of the protective devices can be obtained from the manufacturers.

The following tables give primary and secondary fault currents for different transformer impedances for a fault on the transformer terminals. Use the percent transformer impedance nearest to that of those used on the project.

PRIMARY AND SECONDARY FAULT CURRENTS
7200 VOLT PRIMARY 120/240 VOLT SECONDARY

TRANSFORMER PERCENT IMPEDANCE

120-VOLT FAULT ON THREE-WIRE SERVICE

Transf. KVA	2.00%		2.5%		3.00%		3.5%		4.00%	
	Pri.	Sec.	Pri.	Sec.	Pri.	Sec.	Pri.	Sec.	Pri.	Sec.
1.5	7.84	470	6.28	377	5.24	314	4.47	268	3.92	235
3	15.7	943	12.5	751	10.45	628	8.94	537	7.84	471
5	26.1	1570	20.9	1255	17.40	1045	14.9	895	13.05	784
7.5	39.2	2350	31.4	1885	26.20	1570	22.4	1345	19.60	1178
10	52.2	3140	41.8	2510	34.8	2090	29.7	1780	26.1	1570
240-VOLT FAULT ON THREE-WIRE SERVICE										
1.5	10.4	312	8.34	250	6.95	208	5.95	179	5.21	156
3	20.8	625	16.7	500	13.9	417	11.90	357	10.4	312
5	34.7	1042	27.8	834	23.1	694	19.8	595	17.4	522
7.5	52.1	1562	41.6	1250	34.7	1040	29.8	894	26.1	782
10	69.4	2080	55.5	1667	46.3	1390	39.7	1190	34.7	1040
120-VOLT FAULT ON TWO-WIRE SERVICE										
1.5	10.4	625	8.34	500	6.95	417	5.95	357	5.2	312
3	20.8	1250	16.7	1000	13.9	833	11.9	714	10.4	625
5	34.7	2085	27.8	1667	23.1	1388	19.8	1190	17.4	1042
7.5	52.1	3125	41.6	2500	34.7	2080	29.8	1786	26.1	1562
10	69.4	4160	55.5	3333	46.3	2780	39.7	5380	34.7	2080

Note: The transformer impedance is increased about 33% for a 120 V fault on a three-wire service.

Appendix

Handy Formulas for Fault Calculations

A. Impedance of REA Lines

The general expression for the line impedance, Z_L, in ohms per circuit mile of a multigrounded single phase line is as follows:

$$Z_L = Z_{11} - \frac{(Z_{IN})^2}{Z_{NN}} + \frac{1 - \mu}{S} Z_{NG}$$

where:

Z_{11} (the self impedance of the phase wire with ground return expressed in ohms per mile)

$= (R_e + R_1) + j\,(X_e + X_1)$.

$R_e = 0.00159\,f$, where f is the frequency in cycles per second.

R_1 = effective resistance of phase wire in ohms per mile. The value of R_1 may be obtained from the manufacturers' tables or electrical handbooks.

$X_e = (0.002328)(f)(\log_{10})\ 4{,}665{,}600\ \frac{p}{f}$ where p is the ground resistivity in meter-ohms. A value of 100 meter-ohms is generally assumed if it is not otherwise specified.

X_1 = inductive reactance of the phase wire in ohms per mile for one foot spacing. Values of X_1 are obtainable from manufacturers' tables or electrical handbooks.

Z_{NN} (the self impedance of the neutral wire with ground return expressed in ohms per mile)

$= (R_e + R_N) + j\,(X_e + X_N)$.

R_e and X_e same as in Z_{11} above;

R_N = effective resistance of neutral wire in ohms per mile. This value is available from manufacturers' data or electrical handbooks.

X_N = inductive reactance of the neutral wire expressed in ohms per mile for one foot spacing. Its value is available in manufacturers' data and in handbooks.

Z_{IN} (mutual impedance between phase and neutral wires with ground return expressed in ohms per mile)

$= R_e + j\,(X_e - X_D)$

R_e and X_e same as in Z_{11} above;

$X_D = \frac{2\pi f}{1000}\,(0.741 \log_{10} D)$

D is the spacing between phase and neutral wires in feet.

$X_D = 0.1682$, for $D = 4$ (standard REA single phase spacing) and $f = 60$ cycles/sec.

$$Z_{NG} = \sqrt{R_g\, Z_{NN}}\,(1 - \mu\ )\ \tanh \lambda S.$$

$$R_g = \frac{R}{n}$$

R = resistance per neutral wire ground in ohms.
n = number of grounds per mile.

$$\mu = \frac{Z_{1N}}{Z_{NN}}$$

$$\lambda = \sqrt{\frac{Z_{NN}}{R_g}}$$

S = length of circuit in miles from power source.

The term $\left(\frac{1-\mu}{S} Z_{NG}\right)$ in the general expression of the line impedance, "Z_L", is a corrective factor which depends on the line characteristics and the length "S" of the line. This factor, for "S" equal to or greater than 10, becomes negligible. When there are no grounds on the neutral other than at the source, which is the actual case when "S" is very small, the impedance, "Z_L", becomes the same as that of a metallic single phase circuit.

For two-phase wires and neutral ("V" circuit)

$$Z_a = \left(Z_{aa} - \frac{(Z_{an})^2}{Z_{nn}}\right) + \frac{I_b}{I_a}\left(Z_{ab} - \frac{Z_{an}\, Z_{bn}}{Z_{nn}}\right)$$

$$Z_b = \left(Z_{bb} - \frac{(Z_{bn})^2}{Z_{nn}}\right) + \frac{I_a}{I_b}\left(Z_{ab} - \frac{Z_{an}\, Z_{bn}}{Z_{nn}}\right)$$

where I_a and I_b are equal and 120° apart,

$$Z_a = Z_1 - \frac{Z_2 2}{Z_{nn}}\ (1 + a^2) + a^2\, Z_{ab}$$

$$Z_b = Z_1 - \frac{Z_2 2}{Z_{nn}}\ (1 + a) + a\, Z_{ab}$$

where $Z_1 = Z_{aa} = Z_{bb}$

$Z_2 = Z_{an} = Z_{bn}$

$a = -0.5 + j0.866$

For three-phase wires and neutral

Assume balanced conditions (no ground current).

$$Z_L = r_c + j0.2794 \log_{10} \frac{G.M.D.}{R} \quad \text{for } f = 60 \text{ cycles.}$$

where Z_L = impedance of circuit

r_c = resistance of conductor

G.M.D. = geometric mean spacing

$= (\sqrt[3]{D_1 D_2 D_3}$ for 3 conductors)

R = geometric mean radius of conductor

Values of R for various conductors are shown on page 40.

$$u = -4 \log_e \frac{(R)}{(r)} = -9.210 \log_{10} \frac{(R)}{(r)}$$

where u = permeability

R = geometric mean radius

r = conductor radius (actual)

B. Formulas for fault currents

(1) Three-phase fault.

$$I_a = I_b = I_c = \frac{E}{(Z_1) + Z_f}$$

(2) Line-to-ground fault on phase a.

$$I_a = \frac{E}{\left(\frac{Z_1 + Z_2 + Z_0}{3}\right) + Z_f}$$

$I_b = I_c = 0$

(3) Line-to-line fault between phases b and c.

$I_a = 0$

$$I_c = -I_b = \frac{\sqrt{3}\, E}{(Z_1 + Z_2) + Z_f}$$

where

E = Line to ground voltage

Z_1 = Positive phase sequence impedance

Z_2 = Negative phase sequence impedance

Z_0 = Zero phase sequence impedance

Z_f = Fault impedance

I_a, I_b, I_c, currents in a, b and c phases.

C. Delta-Wye transformer bank current conversion formulas.

(1) Three-phase fault

$$I_{sa} = I_{sc} = \sqrt{\quad 3 \qquad} \quad (N) \quad (I_L)$$

(2) Line-to-ground fault

$$I_{sa} = I_{sb} = (N) \quad (I_L)$$

$$I_{sc} = 0$$

(3) Line-to-line fault

$$I_{sa} = 2(N) \quad (I_L)$$

$$I_{sb} = I_{sc} = (N) \quad (I_L)$$

where

I_{sa}, I_{sb}, I_{sc}, Line current in phases a, b and c on delta (supply) side.

I_L = fault current on wye (load) side.

N = Transformer turns ratio

$$= \left(\frac{E_L}{E_s\ (L\text{-}L)} \right) \text{ for delta-wye bank}$$

D. <u>Decrement of positive sequence current in alternators</u>.

$$T'_d = \frac{X'_d}{X_d} (T_{do}) \text{ for circuit having negligible resistance}$$

$$T'_d = \frac{X'_d \;\; X_q + r^2}{X_d \;\; X_q + r^2} \; T_{do} \text{ for circuit with resistance}$$

where

T_d' = transient time constant

X_d' = direct axis transient reactance (including line and machine)

X_q = quadrature axis synchronous reactance

X_d = direct axis synchronous reactance (including machine and line)

r = resistance of machine and line

T_{do} = open circuit time constant

$$\text{Then } I' = (I_i' - I)\,(e)^{\left(\frac{-t}{T_d'}\right)} + I$$

where

I' = positive sequence transient current at anytime

I_i' = initial transient current

I = sustained short circuit current (from synchronous impedance)

e = 2.7183

(This neglects the subtransient value and the action of the voltage regulator)

E. Percent and per unit formulas.

$$(\%\text{ impedance}) = \frac{\text{ohms (KVA)}}{(\text{KV})^2(10)}$$

$$\text{ohms} = \frac{(\%\text{ impedance})\ (\text{KV})^2(10)}{\text{KVA}}$$

If KVA is per phase, KV must be the line-to-ground value.
If KVA is total, KV must be the line-to-line value.

$$\text{per unit impedance} = \frac{\text{percent impedance}}{100}$$

To convert ohmic values from one voltage base to another, multiply by the square of the ratio of the line-to-ground voltages. (See above formulas.)

F. Geometric Mean Radius of Conductors

Solid round conductor	0.779 r
Full stranding, non-magnetic	
7 strands	0.726 r
19 strands	0.758 r
where r = ½ of actual conductor diameter	
Rectangular section of sides a and b	0.2235(a + b)

A.C.S.R. conductors

2/0	0.0612 inches
1/0	0.0535 "
1	0.0502 "
2	0.0502 "
4	0.0523 "

Copper - Copperweld Conductors

Strands	Conductor		
7	7 copperweld	0.223	r
7	3 copperweld, 4 copper	0.3165	r
1	Solid copperweld	0.287	r
3	Type A, 1 copperweld, 2 copper	0.333	r
3	Type D, 2 copperweld, 1 copper	0.242	r
19	7 copperweld, 12 copper	0.564	r
3	3 copperweld	0.223	r

where r = ½ actual conductor diameter

Amerductor Conductors

Size		
2	0.255	r
4	0.414	r
6	0.504	r
8	0.592	r
8X	0.537	r
9X	0.181	r
10	0.211	r
12	0.129	r

Three strand steel

U. S. DEPARTMENT OF AGRICULTURE
RURAL ELECTRIFICATION ADMINISTRATION

AVERAGE R.E.A. SINGLE PHASE LINE IMPEDANCE FOR MULTI-GROUNDED NEUTRAL LINES
To Nearest 0.1 Ohm.

EARTH RESISTIVITY EQUALS 100 METER OHMS

Miles	Conductor Copper Equivalent Size															
	1/0		1		2		4		6		8		9½		11(3#12)	
	R_L	X_L	R_L	X_L	R_L	X_L	R_L	X_L	R_L	X_L	R_L	X_L	R_L	X_L	R_L	X_L
1	0.7	1.1	0.9	1.1	1.0	1.2	1.6	1.3	2.5	1.5	3.7	1.6	5.0	1.7	7.4	1.7
2	1.5	2.3	1.8	2.3	2.0	2.4	3.3	2.6	4.9	2.9	7.5	3.1	10.1	3.3	14.7	3.4
3	2.2	3.4	2.6	3.4	3.0	3.7	4.9	3.9	7.4	4.4	11.2	4.7	15.1	5.0	22.1	5.1
4	2.9	4.5	3.5	4.6	4.0	4.9	6.5	5.2	9.8	5.8	15.0	6.2	20.2	6.7	29.4	6.8
5	3.6	5.6	4.4	5.7	5.0	6.1	8.2	6.6	12.3	7.3	18.7	7.8	25.2	8.4	36.8	8.5
6	4.3	6.7	5.3	6.8	6.0	7.3	9.8	7.9	14.7	8.8	22.4	9.3	30.2	10.0	44.2	10.2
7	5.1	7.9	6.1	8.0	7.0	8.5	11.4	9.2	17.2	10.2	26.2	10.9	35.3	11.7	51.5	11.9
8	5.8	9.0	7.0	9.1	8.0	9.8	13.0	10.5	19.6	11.7	29.9	12.4	40.3	13.4	58.9	13.6
9	6.5	10.1	7.9	10.2	9.0	11.0	14.7	11.8	22.1	13.1	33.7	14.0	45.4	15.0	66.2	15.3
10	7.2	11.2	8.8	11.4	10.0	12.2	16.3	13.1	24.5	14.6	37.4	15.5	50.4	16.7	73.6	17.0
11	8.0	12.4	9.6	12.5	11.0	13.4	17.9	14.4	27.0	16.1	41.1	17.1	55.4	18.4	81.0	18.7
12	8.7	13.5	10.5	13.7	12.0	14.6	19.6	15.7	29.4	17.5	44.9	18.6	60.5	20.0	88.3	20.5
13	9.4	14.6	11.4	14.8	13.0	15.9	21.2	17.0	31.9	19.0	48.6	20.2	65.5	21.7	95.7	22.2
14	10.1	15.7	12.3	15.9	14.0	17.1	22.8	18.3	34.3	20.4	52.4	21.7	70.6	23.4	103.0	23.9
15	10.9	16.9	13.1	17.1	15.0	18.3	24.5	19.7	36.8	21.9	56.1	23.3	75.6	25.1	110.4	25.6
16	11.6	18.0	14.0	18.2	16.0	19.5	26.1	21.0	39.2	23.4	59.8	24.8	80.6	26.7	117.8	27.3
17	12.3	19.1	14.9	19.4	17.0	20.7	27.7	22.3	41.7	24.8	63.6	26.4	85.7	28.4	125.1	29.0
18	13.0	20.2	15.8	20.5	18.0	22.0	29.3	23.6	44.1	26.3	67.3	27.9	90.7	30.1	132.5	30.7
19	13.7	21.4	16.6	21.6	19.0	23.2	31.0	24.9	46.6	27.7	71.1	29.5	95.8	31.7	139.8	32.4
20	14.5	22.5	17.5	22.8	20.0	24.4	32.6	26.2	49.0	29.2	74.8	31.0	100.8	33.4	147.2	34.1
21	15.2	23.6	18.4	23.9	21.0	25.6	34.2	27.5	51.5	30.7	78.5	32.6	105.8	35.1	154.6	35.8
22	15.9	24.7	19.3	25.0	22.0	26.8	35.9	28.8	53.9	32.1	82.3	34.1	110.9	36.7	161.9	37.5
23	16.6	25.9	20.2	26.2	23.0	28.1	37.5	30.1	56.4	33.6	86.0	35.7	115.9	38.4	169.3	39.2
24	17.4	27.0	21.0	27.3	24.0	29.3	39.1	31.4	58.8	35.0	89.8	37.2	121.0	40.1	176.6	40.9
25	18.1	18.1	21.9	28.4	25.0	30.5	40.8	32.8	61.3	36.5	93.5	38.8	126.0	41.8	184.0	42.6

U. S. DEPARTMENT OF AGRICULTURE

RURAL ELECTRIFICATION ADMINISTRATION

IMPEDANCE OF REA LINES
OHMS PER CIRCUIT MILE

Standard REA Spacing (3¢ = 4.69', 1¢ = 4') Earth Resistivity — 100 Meter-Ohms

WIRE SIZE OR DESIGNATION	IMPEDANCE TO POSITIVE OR NEGATIVE SEQUENCE CURRENT 3 PHASE LINES		SINGLE PHASE IMPEDANCE WITH MULTI-GROUNDED NEUTRAL WIRE		
	$R_1 = R_2$	$X_1 = X_2$	R	X	Z
Copper Conductors — 25°C					
2/0	0.440	0.719	0.57	1.12	1.26
1/0	0.555	0.733	0.70	1.15	1.35
1	0.699	0.747	0.876	1.139	1.435
2	0.873	0.758	1.07	1.220	1.62
4	1.374	0.796	1.600	1.33	2.08
6	2.180	0.824	2.410	1.44	2.80
Copperweld — Copper Conductors — 25°C					
2A	0.876	0.778	1.07	1.26	1.65
4A	1.39	0.807	1.61	1.34	2.10
6A	2.21	0.835	2.44	1.45	2.84
8A	3.51	0.853	3.72	1.54	4.03
9½D	4.93	0.896	5.12	1.61	5.37
3-12	7.46	0.968	7.62	1.71	7.81
A.C.S.R. Conductors — 25°C					
4/0	0.445	0.711	0.57	1.10	1.31
3/0	0.560	0.727	0.71	1.24	1.43
2/0	0.706	0.741	0.87	1.28	1.54
1/0	0.888	0.755	1.08	1.32	1.70
2	1.410	0.779	1.63	1.39	2.15
4	2.240	0.798	2.47	1.46	2.87
6	3.560	0.830	3.78	1.51	4.08
Amerductor Conductors — 20°C					
2	0.900	0.853	1.08	1.36	1.74
4	1.420	0.822	1.66	1.39	2.17
6	2.165	0.825	2.40	1.49	2.82
8	3.485	0.835	3.70	1.56	4.02
8X	3.22	0.835	3.43	1.54	3.77
9X	4.0	0.981	4.27	1.66	4.59
10	5.60	0.946	5.77	1.70	6.00
12	8.862	1.034	9.03	1.83	9.21

No account is taken of ground contact resistance.

U. S. DEPARTMENT OF AGRICULTURE

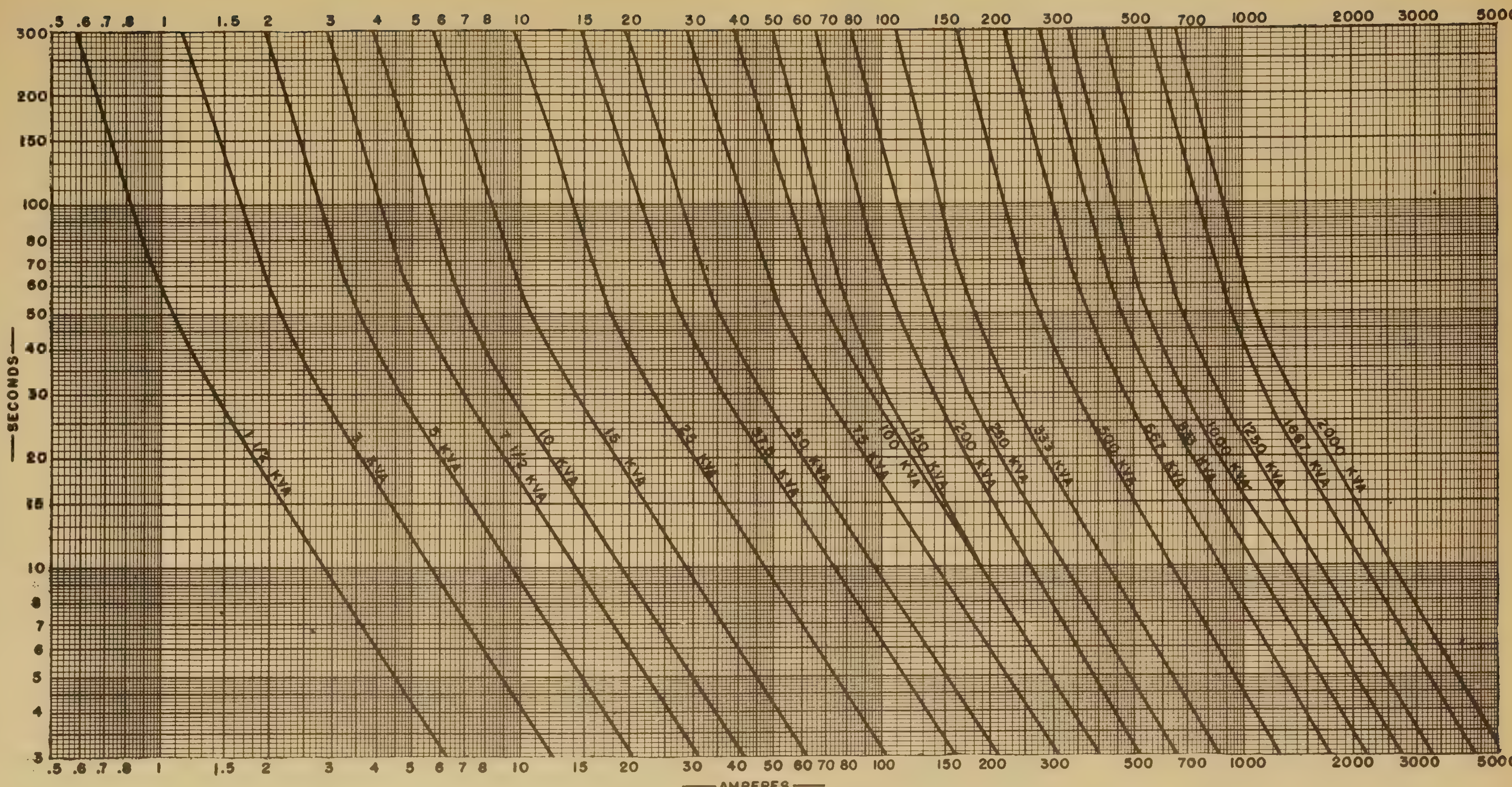
RURAL ELECTRIFICATION ADMINISTRATION

IMPEDANCE OF R.E.A. LINES
OHMS PER CIRCUIT MILE AT 20° C

Standard R.E.A Spacing Amerstell Type 35-130 Earth Resistivity - 100 Meter-ohms

Size B.W.G.	60 Cycle Current Amperes	IMPEDANCE TO POSITIVE OR NEGATIVE SEQUENCE CURRENT THREE PHASE LINES		SINGLE PHASE IMPEDANCE WITH MULTI-GROUNDED NEUTRAL WIRE (Neutral same size as phase wire)		
		$R_1 = R_2$	$X_1 = X_2$	R	X	Z
4	1	8.07	1.45	8.24	2.18	8.52
	2.5	8.20	1.46	8.37	2.19	8.65
	5	8.39	1.50	8.55	2.24	8.84
	7.5	8.60	1.53	8.76	2.27	9.05
	10	8.83	1.58	8.99	2.32	9.29
	15	9.53	1.63	9.69	2.37	9.98
	20	10.05	1.80	10.20	2.54	10.51
	25	10.72	2.24	10.87	2.98	11.27
	50	14.90	3.32	15.04	4.07	15.58
	75	16.20	3.42	16.33	4.17	16.85
	100	15.40	3.37	15.54	4.12	16.08
6	1	11.29	1.47	11.44	2.22	11.65
	2,5	11.31	1.48	11.46	2.23	11.67
	5	11.36	1.52	11.51	2.27	11.73
	7.5	11.43	1.55	11.58	2.30	11.81
	10	11.53	1.60	11.68	2.35	11.91
	15	11.81	1.71	11.96	2.46	12.21
	20	12.20	1.90	12.35	2.65	12.63
	25	13.01	2.33	13.15	3.08	3.51
	50	21.85	3.55	21.98	4.31	22.40
	60	22.54	3.64	22.67	4.40	23.09
	75	22.00	3.53	22.13	4.29	22.54
	100	20.20	3.28	20.33	4.04	20.73

Note - Ground contact resistance neglected.



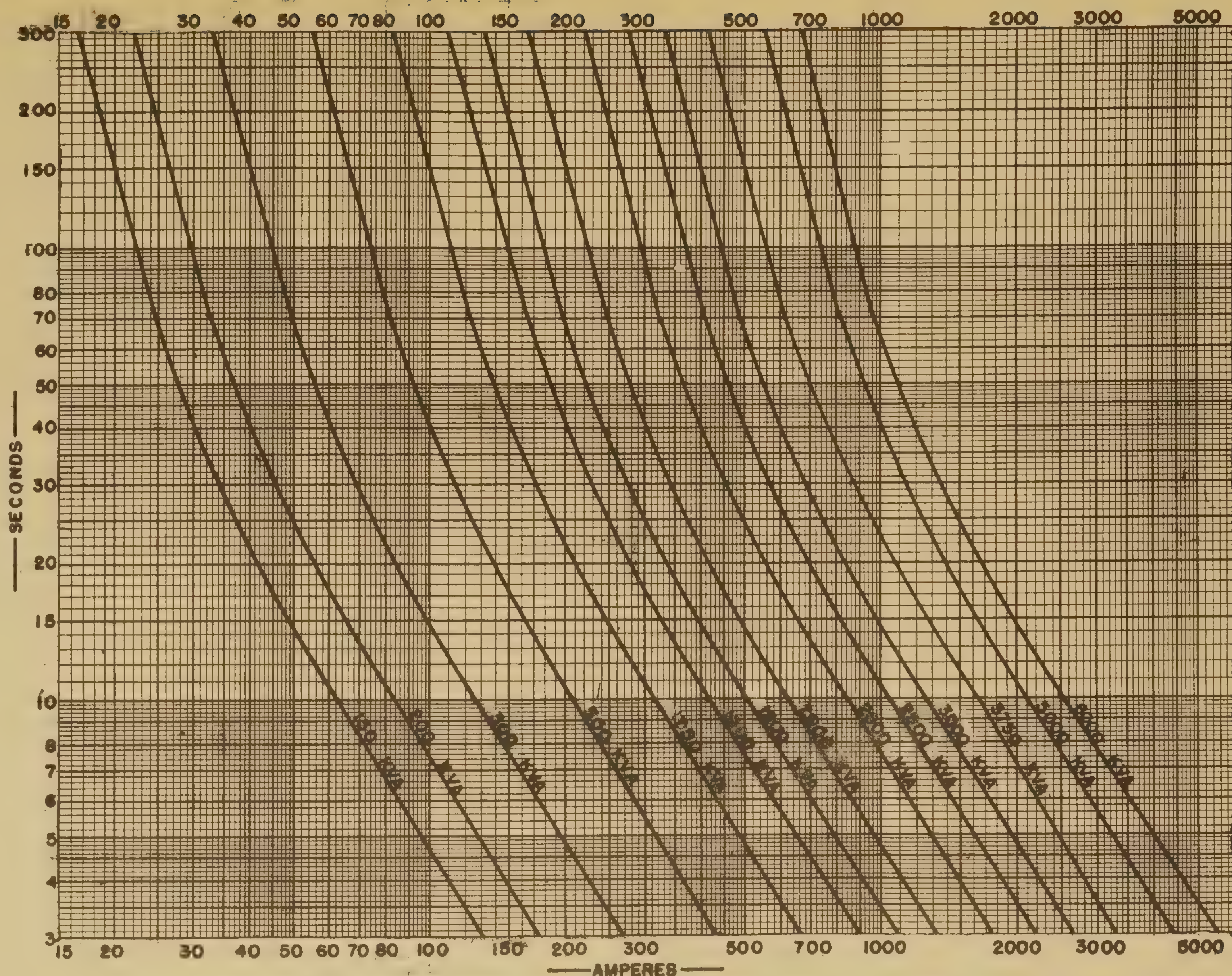
PERMISSIBLE EMERGENCY SHORT TIME OVERLOADS, FOLLOWING FULL LOAD

SINGLE PHASE 7200 VOLT TRANSFORMERS
FROM A.S.A. RECOMMENDED PRACTICES C57.3-1942

FOR OTHER LINE TO GROUND VOLTAGE "N", MULTIPLY AMP. SCALE BY $\frac{7200}{N}$

U.S. DEP'T OF AGRICULTURE
RURAL ELECTRIFICATION ADM. — NOV. 1943

CURVE SHEET I-A



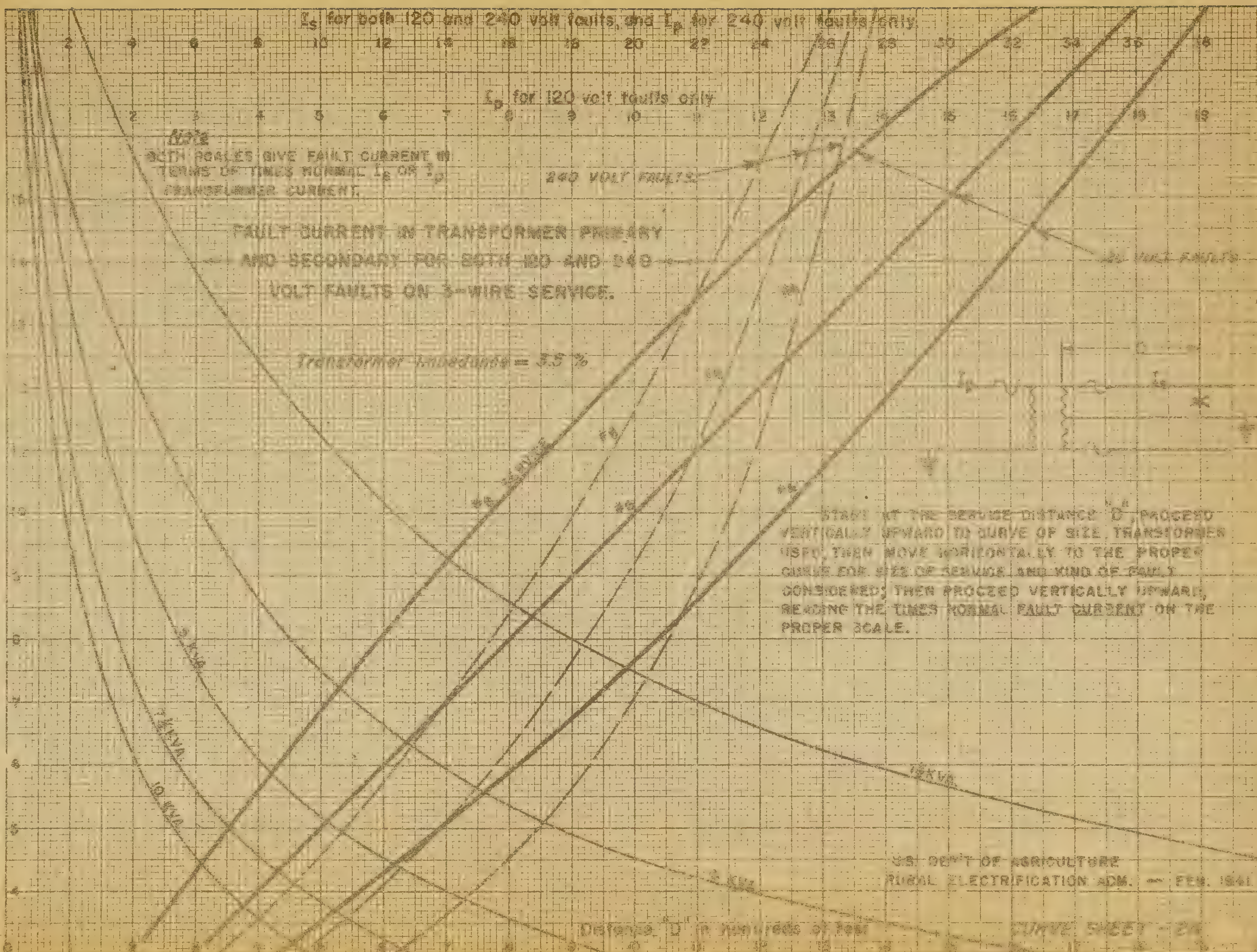
PERMISSIBLE EMERGENCY SHORT TIME OVERLOADS, FOLLOWING FULL LOAD

THREE PHASE 7200 VOLT TRANSFORMERS

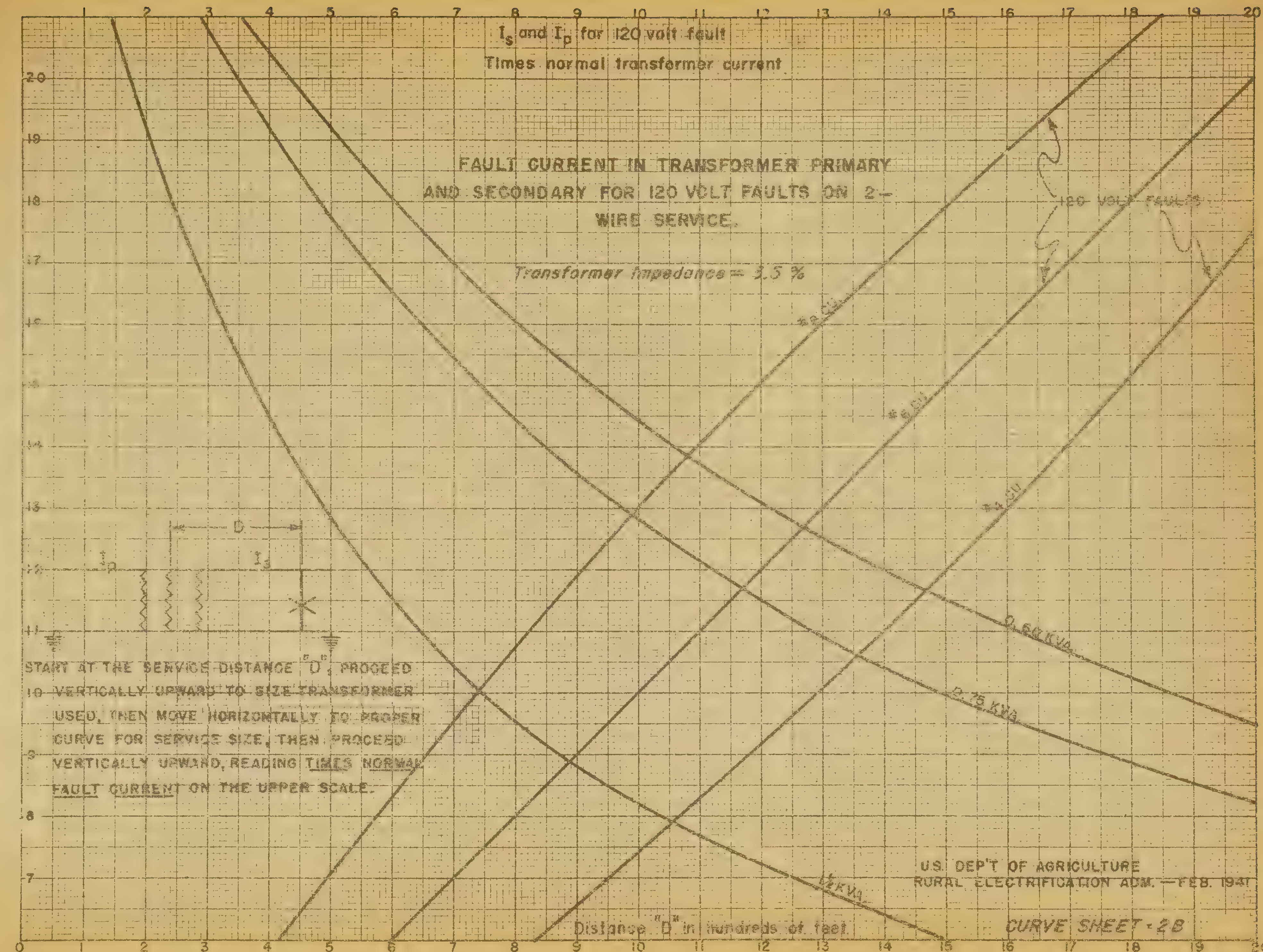
FROM A.S.A. RECOMMENDED PRACTICES C 57.3-1942

FOR OTHER LINE TO GROUND VOLTAGE "N", MULTIPLY AMP. SCALE BY $\frac{7200}{N}$

U.S. DEP'T. OF AGRICULTURE
RURAL ELECTRIFICATION ADM. — NOV. 1945
CURVE SHEET 1—B

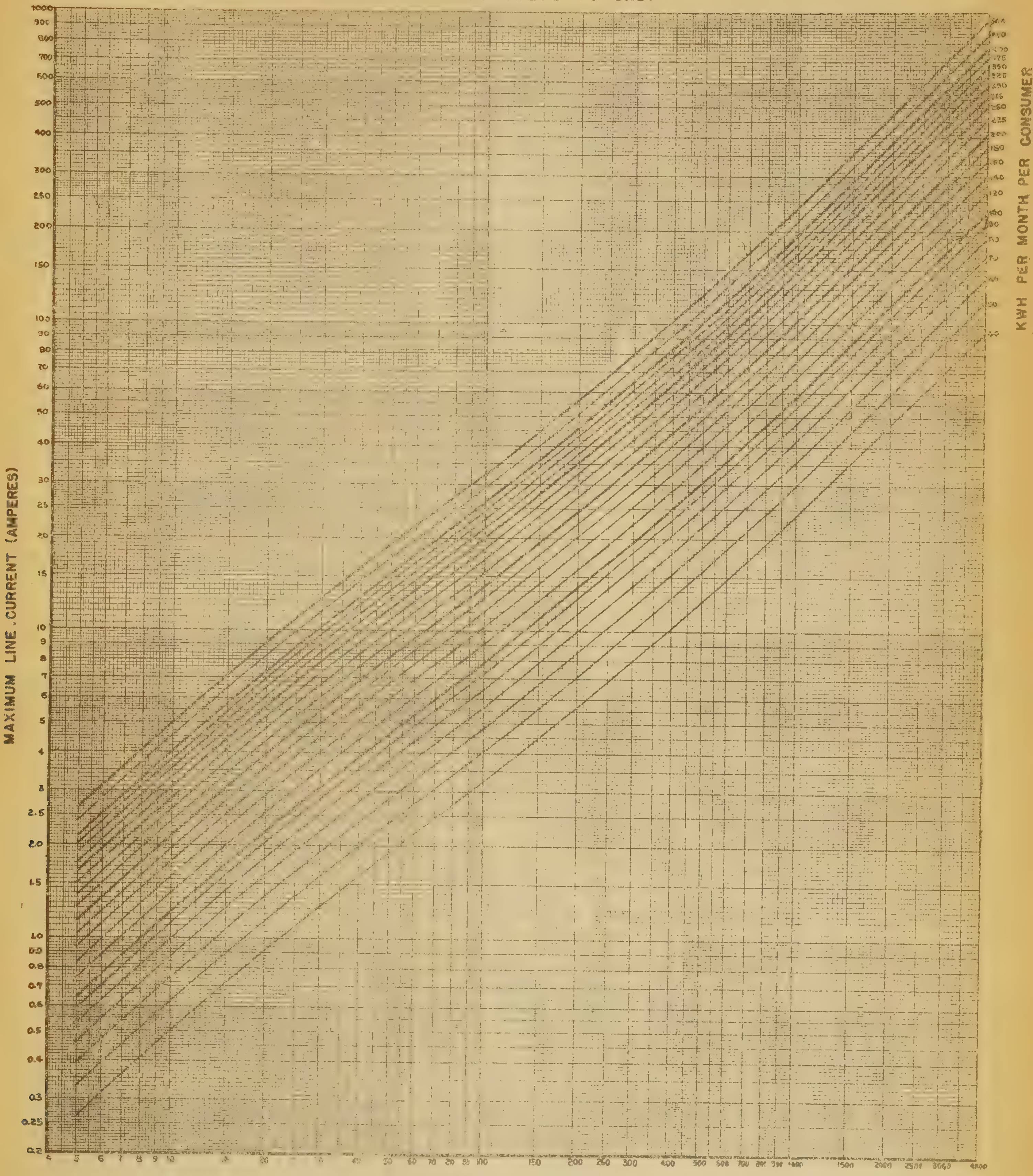


I_s for both 120 and 240 volt faults, and I_p for 240 volt faults only
I_p for 120 volt faults only
Note
BOTH SCALES GIVE FAULT CURRENT IN TERMS OF TIMES NORMAL I_s OR I_p TRANSFORMER CURRENT.
240 VOLT FAULTS
FAULT CURRENT IN TRANSFORMER PRIMARY AND SECONDARY FOR BOTH 120 AND 240 VOLT FAULTS ON 3-WIRE SERVICE.
Transformer Impedance = 3.5 %
3 KVA
7½ KVA
10 KVA
15 KVA
5 KVA
START AT THE SERVICE DISTANCE "D", PROCEED VERTICALLY UPWARD TO CURVE OF SIZE TRANSFORMER USED, THEN MOVE HORIZONTALLY TO THE PROPER CURVE FOR SIZE OF SERVICE AND KIND OF FAULT CONSIDERED; THEN PROCEED VERTICALLY UPWARD, READING THE TIMES NORMAL FAULT CURRENT ON THE PROPER SCALE.
U.S. DEP'T OF AGRICULTURE
RURAL ELECTRIFICATION ADM. — FEB. 1941
Distance "D" in hundreds of feet
CURVE SHEET - 2A


I_s and I_p for 120 volt fault
Times normal transformer current
FAULT CURRENT IN TRANSFORMER PRIMARY AND SECONDARY FOR 120 VOLT FAULTS ON 2-WIRE SERVICE.
Transformer impedance = 3.5 %
120 VOLT FAULTS
#2 CU
#6 CU
#4 CU
0.60 KVA
0.75 KVA
D
I_s
I_p
START AT THE SERVICE DISTANCE "D", PROCEED VERTICALLY UPWARD TO SIZE TRANSFORMER USED, THEN MOVE HORIZONTALLY TO PROPER CURVE FOR SERVICE SIZE, THEN PROCEED VERTICALLY UPWARD, READING TIMES NORMAL FAULT CURRENT ON THE UPPER SCALE.
U.S. DEP'T OF AGRICULTURE
RURAL ELECTRIFICATION ADM. — FEB. 1941
Distance "D" in hundreds of feet
CURVE SHEET - 2B

MAXIMUM LOAD CURRENT

SINGLE PHASE — 7200 VOLTS TO GND.



For other voltage "n", multiply current value by $\frac{7200}{n}$

DESIGN AND CONSTRUCTION DIVISION
RURAL ELECTRIFICATION ADMINISTRATION

1/2/46

FORM TS-2R

U.S. DEP'T OF AGRICULTURE RURAL ELECTRIFICATION ADMINISTRATION	SECTIONALIZING STUDY	Sheet..........of..........sheets PROJECT
	SUBMITTED BY..........................	DATE..........................
	CHECKED BY..........................	DATE..........................

	TYPE OF FAULT CALCULATED		
	LINE TO GRD.	LINE TO LINE	3 ø
A — IMPEDANCE OF SOURCE			
1. PLANT			
(a) DIRECT AXIS TRANSIENT REACTANCE — FULL LOAD -------			
(b) NEGATIVE SEQUENCE " — " " -------			
(c) DIRECT AXIS TRANSIENT REACTANCE — MINIMUM " -------			
(d) NEGATIVE SEQUENCE " " " -------			
(e) EQUIVALENT PLANT REACTANCE FULL LOAD -------			
(f) EQUIVALENT PLANT REACTANCE MINIMUM LOAD -------			
2. TIE LINE AND TIE LINE TRANSFORMERS			
(g) RESISTANCE REFERRED TO LOAD VOLTAGE -------			
(h) REACTANCE " " " " -------			
3. TOTAL			
(i) MAXIMUM LOAD 1. RESISTANCE EQUAL (g) -------			
2. REACTANCE " (e) + (h) -------			
(j) MINIMUM LOAD 1. RESISTANCE " (g) -------			
2. REACTANCE " (f) + (h) -------			
4. FOR LARGE SUPPLY SYSTEM ONLY			
(k) MAXIMUM LOAD REACTANCE -------			
(l) MINIMUM " " -------			
B — IMPEDANCE OF SUBSTATION			
(m) Z_T -------			
(n) R_T -------			
(o) X_T -------			
C — TOTAL IMPEDANCE OF SOURCE AND SUBSTATION			
(p) MAXIMUM CONDITIONS			
1. $R = (n) + (i_1)$ -------			
2. $X = (o) + (i_2)$ or (k) -------			
(q) MINIMUM CONDITIONS			
1. $R = (n) + (j_1)$ -------			
2. $X = (o) + (j_2)$ or (l) -------			

IED

FORM TS-3

U.S. DEPARTMENT OF AGRICULTURE

RURAL ELECTRIFICATION ADMINISTRATION

SECTIONALIZING STUDY

SHEET ____ OF ____ SHEETS

———— PROJECT ————

SUBMITTED BY ________ DATE ________

CHECKED BY ________ DATE ________

r	POINT																	
s	PRECEDING POINT ON LINE TOWARD SUBSTATION																	
t	MILES FROM PREVIOUS POINT ON LINE TOWARD SUBSTATION																	
u	COPPER CONDUCTIVITY SIZE, SECTION FROM PREVIOUS POINT																	
v	TYPE OF FAULT CALCULATED																	
w	RESISTANCE "R", SECTION FROM PREVIOUS POINT																	
x	RESISTANCE "R", BACK TO SUBSTATION																	
y	FOR. MAX. CONDITION, TOTAL RESISTANCE TO SOURCE $= x + p_1$																	
z	FOR MIN. CONDITION, TOTAL RESIST TO SOURCE $= y +$ FAULT RESIST.																	
aa	REACTANCE "X", SECTION FROM PREVIOUS POINT																	
ab	REACTANCE "X", BACK TO SUBSTATION																	
ac	FOR MAX. CONDITION, TOTAL REACTANCE TO SOURCE $= ab + p_2$																	
ad	FOR MIN. CONDITION, TOTAL REACTANCE TO SOURCE $= ab + q_2$																	
ae	FOR MAX. CONDITION, TOTAL IMPEDANCE TO SOURCE $= \sqrt{y^2 + ac^2}$																	
af	FOR MIN. CONDITION, TOTAL IMPEDANCE TO SOURCE $= \sqrt{z^2 + ad^2}$																	
ag	MAX. CURRENT "I" $= \frac{\text{VOLTAGE}}{ae}$																	
ah	MIN. CURRENT "I" $= \frac{\text{VOLTAGE}}{af}$																	

FORM TS-4R

U.S. DEP'T OF AGRICULTURE RURAL ELECTRIFICATION ADMINISTRATION	SECTIONALIZING STUDY	Sheet ______ of ______ sheets PROJECT
	SUBMITTED BY ______________ DATE ________	
	CHECKED BY ______________ DATE ________	

This Study is based on the use of the following makes of Sectionalizing Equipment: ______

	BREAKERS	FUSE LINKS
1. Substation — Supply Side		
2. Substation — Load Side		
3. Lines		

POINT	MAX. LOAD CURRENT	MAX. FAULT CURRENT	MIN. FAULT CURRENT*	PRESENT DEVICE		DEVICE TO BE INSTALLED		REMARKS
				TYPE	DISPOSITION	TYPE	RATING	

* MINIMUM FAULT CURRENT AT END OF CONTROLLED SECTION.

Sample Problem

This is a sample only. It does not necessarily indicate an actual case, and the results are not necessarily those recommended by REA. The sample only illustrates a procedure. Attached is an incomplete circuit diagram on page 58 of Somestat 39 Smith, showing tentative sectionalizing. The distribution system receives power from a Diesel plant which has four 4800-volt units of 1000 kva each, three of which run during peak load, and one of which runs at light load. The constants of all generators are as follows:

(1) Direct-axis transient reactance - 0.315 per unit (31.5 percent)

(2) Negative sequence reactance - 0.195 per unit (19.5 percent)

The plant is considered sufficiently large so that decrement may be neglected. The three-mile line from the generating plant to the substation is #4/0 copper with four foot equivalent spacing and the voltage is 4800, line-to-line. The REA substation has three 200 kva transformers of 3.95% impedance connected delta-wye with 7200 volts line-to-ground on the load side. Tenative positions for sectionalizing devices have been selected as shown. The maximum fuse at the supply side of the substation allowed by the power supply company is a 200-ampere Presto type K power fuse, with melting time curve as shown by plate "A", page 61 Plate "B", page 62, shows part of the total clearing time curves for all sizes of the Super #XX-ID fuse link used on this system. Plate "C", page 63, shows the remaining part of these total clearing time curves and the first opening time of the OC-type LM oil circuit recloser. There is an oil circuit breaker in the plant controlled by an Electro type PB relay, which is connected to the main circuit with a 200/5 current transformer.

Table (1), pages 59 and 60, is a coordination table for the Super fuse link. Two, three and five kva distribution transformers are fused with a 2-ampere Super #XX-ID fuse. There is no larger size of transformer than 5 kva on the system. The peak load may be taken as 1 kva per phase-mile throughout. Make a complete sectionalizing study of the system.

Sample Problem - Solution

Forms TS-2R and TS-3 are self-explanatory. A fault resistance of 40 ohms was used in obtaining the minimum fault current for a line-to-ground fault. The maximum and minimum fault currents after calculation on Form TS-3 are placed directly on the circuit diagram as shown. The line-to-line and three-phase faults were calculated at the substation and at points 2A2, 2C2 and B7, C7. The minimum fault current for the section controlled by fuses 2A1, 2B1 and 2C1 is at points 2A2, 2C2 and 2B4 (second sectionalizing point from substation) and is 91.9 amperes. From curve sheet 1A, the time in which the 200 kva transformers would be damaged at 91.9 amperes is 92 seconds. From Plate "B" the total clearing time of a 45-ampere Super #XX-ID fuse is 6.4 seconds at 91.9 amperes.

Since 2A1, 2B1 and 2C1 are 3-shot, 3 times 6.4 is a total clearing time of 19.2 seconds, which is considerably below the failure time of the transformer, and hence 3-shot, 45-ampere fuses at 2A1, 2B1 and 2C1 are safe.

The total clearing time of a 50-ampere fuse at 91.9 amperes is 60 seconds, and of three of these is 180 seconds, and hence the 50-ampere fuses would not protect the transformers. If desired, the 3-shots at 2A1, 2B1 and 2C1 could be fused as a 10-45-45 combination. The use of the 10-ampere fuse in the first shot can be expected to lessen the number of trips to outlying fuses, and lower the outage time. Since the load is only about 40 kva, or about 6-amperes, the 10-ampere fuse will carry the normal maximum load.

The maximum fault current at 2A1, 2B1 and 2C1 is 253 amperes, a line-to-ground value. From formula (13) this gives 380 amperes through the supply side fuse. With 2A1, 2B1 and 2C1 fused 10-45-45, the total clearing time of these fuses at 253 amperes is 0.029 + 0.305 + 0.305 = 0.639 seconds, from Plate "C", (neglecting reclosing time). Since Plate "A" shows melting time of the supply side fuse, divide 0.639 by 0.75 to obtain 0.852 seconds as the value to use to prevent damage of the supply side fuse. 0.852 seconds on Plate "A" gives the current in percent of the fuse rating at 360%. Since the supply current is 380 amperes, the fuse size must be $\frac{380}{3.60} = 105.6$ amperes. From the catalog, the next larger sizes are 150 and 200 amperes.

To check coordination for three-phase faults, we see that the maximum three phase fault at 2A1, 2B1 and 2C1 is 177 amperes, which is 460 amperes through the supply side fuse by formula (14). Total clearing time for the fuses at 2A1, 2B1 and 2C1 at 177 amperes is 0.048 + 0.64 + 0.64 = 1.33 seconds, and this divided by 0.75 gives 1.77 seconds damage time. The current corresponding to this damage time in percent of the supply side fuse rating is 255% from Plate "A". The supply side fuse size is therefore $\frac{460}{2.55} =$ 180.5 amperes.

The standard 200 ampere size will therefore provide coordination for three phase faults.

The maximum line-to-line fault current is 166 amps, or 498 amperes on the low voltage side by formula (15). The total clearing time of fuses at 2A1, 2B1 and 2C1 at 166 amperes is 1.55 seconds. Repeating the above process the supply side fuse must be $\frac{498}{2.40} = 208$ amperes in size.

This is somewhat over the 200 limiting figure, but rather than reduce the load side fuse sizes, operation will be continued on this basis, taking a chance on an occasional supply side fuse failure. (Since three phase and line-to-line faults are rare compared to line-to-ground faults, it may often be necessary to coordinate using the line-to-ground formula.) It can be seen that the line-to-line faults are the worst condition for supply and load side coordination.

To select the breakers at A1, B1 and C1, the procedure is as follows: the second sectionalizing point on the main branch is B7, C7, where the minimum fault current is 83.8 amperes. From Plate "C", the 50-ampere recloser initially opens at a minimum of 130 amperes, and hence cannot be used at points A1, B1 and C1 because there is insufficient pick-up current. The 35-ampere recloser opens at a minimum of 74-amperes, which is less than 83.8 amperes and hence may be used. The first opening time of the 35-ampere breaker on 83.8 amperes is 0.47 seconds, and this times 4 is 1.88 seconds, which is much lower than the damaging time of the 200 kva substation transformer on this current, and hence the breaker is safe in protecting the substation transformers. If desired, a fuse could be used between breaker A1, B1 and C1 and the substation to give back-up protection for currents less than 74 amperes.

To check coordination of the breakers at A1, B1 and C1 with the supply side fuse, use four times the first opening time of the breakers. At 166 amperes, this time is 0.42 seconds. The line-to-line fault current referred to the supply side is 498 amperes (see above), or 249% of the 200 ampere fuse rating previously selected. At the 249% point on Plate "A", we find the time to melt the supply side fuse is 1.85 seconds, or to damage it is about 0.75(1.85) = 1.39 seconds. The damage time of 1.39 seconds is over 3 times the 0.42 seconds required to lock-out the breaker and hence coordination is satisfactory. (For a breaker, further check must sometimes be made at the minimum fault current, but here the time spread is so great that is not necessary).

The sectionalizing apparatus at the substation is therefore definitely selected as follows:

(1) Supply side fuse - 200 ampere Presto Type K
(2) 2A1, 2B1 and 2C1 - 10-45-45 ampere fuses, Super #XX-1D
(3) A1, B1, and C1 - 35 ampere recloser OC, Type LM

Now start at point 2C11 using the fuse coordination table. The maximum line-to-ground fault current at point 2C11 is 138 amperes. A 2 ampere transformer fuse (protecting link--see left-hand column) will protect a 15 ampere fuse (protected link--see top row) up to 140 amperes. Hence tentatively use a 15 ampere fuse at point 2C11. From Plate "B", the current necessary to blow the 15 ampere fuse in 100 seconds is 21 amperes, and since the minimum fault current at the end of the long line (2C12) is 66.6 amperes, the 15 ampere fuse is satisfactory from this standpoint.

At point 2C9, a 20 ampere fuse is necessary to be protected by a 3 ampere transformer fuse, and the same is true at points 2A3 and 2B5. The maximum fault current at 2A3 and 2B5 is 180.5 amperes, and these cutouts are 2-shots. The table shows that a 20 ampere 2-shot (left-hand column) will protect a 40 ampere fuse up to 200 amperes; however, 40 ampere fuses at points 2A2, 2C2 or 2B4 will not coordinate with the previously chosen 45 ampere fuses at 2A1, 2B1 and 2C1. If we make the cutouts at 2A3 and 2B5 single-shots, 30 ampere fuses can be used at 2A2, 2C2 and 2B4, since a 30 ampere fuse will be protected by a single 20 ampere fuse up to 200 amperes fault current. The 30 ampere fuses at 2A2, 2C2 and 2B4 will now coordinate with the 45 ampere links at 2A1, 2B1 and 2C1, providing 2A2, 2C2 and 2B4 are two-shot cutouts, but not if the cutouts at 2A2 and 2C2 are three-shot.

An alternate solution might be to fuse points 2B5, 2A3, 2C9 and 2C11 with 10 ampere links. Then 2-shot 10 ampere fuses at 2A3 and 2B5 would protect 30 ampere fuses at 2A2, 2C2 and 2B4. In the latter case, the fuses at points 2B5, 2A3, 2C9 and 2C11 would not coordinate properly with the transformer cutout fuses, but extra shots could be added at all sectionalizing points, so that primary outages could be reduced. In fact, 2-shot cutouts could also be installed at points 2C9 and 2C11 if desired.

This is the solution shown in the final circuit diagram. (It is not necessarily to be preferred. Local judgment must rule in cases of this kind). In the final set-up shown failure of a transformer fuse on any of the branch lines controlled by 10 ampere line fuses would also probably damage the first shot in the line fuse. Hence the lineman should replace the first line sectionalizing fuse link upon such an occurence. Also, the use of the 10-ampere fuse in the first shot at the substation will provide three-shot protection for all main lines and save lengthy service trips, but will of course not coordinate properly with the branch line 10-ampere fuse links. Hence, a fault on the branch line may damage or blow the first fuse link at 2A1, 2B1 or 2C1 at the same time as the branch fuse blows. It can be seen that in any case, that 3-shot 30-ampere fuses at 2A2, and 2C2 will not coordinate with the 45-ampere fuse at 2A1, 2B1 or 2C1, and hence a two-shot must be used.

Turning to the other main branch, it can be seen that if a 35 ampere reclosing breaker is installed at A1, B1 and C1, a 25 ampere size can be installed at B7 and C7 and 12 ampere sizes at B9 and C10 east. (Since there are gapped transformers beyond B9, there must be a recloser at point B9). The minimum current in the section controlled by the breakers at B7 and C7 is 76.9 amperes, which is in excess of the 62 ampere "pick-up" point. The minimum in the section controlled by breaker C10 east is 55 amperes, which is in excess of the 30 ampere "pick-up" point for the 12 ampere breaker. Similarly, reclosing breaker B9 is satisfactory.

From Plate "C", the largest fuse size which will coordinate with a 12 ampere breaker at C10 east is a 3 ampere size. In other words, with any fuse larger than a 3 ampere size, the breaker will open on a fault before the fuse. Also, it can be seen from the table that a 3 ampere fuse will not be protected by a 2 ampere transformer fuse for any value of fault current. There are three possible solutions to this problem.

(1) Do not use any fuses at C15, C16, C17 or C18, but use manual switches at these points.
(2) Use a fuse at C10 east instead of a breaker.
(3) Fuse cutouts at points C15, C16, C17 and C18, or some of them, with 2- or 3-shot 3 ampere fuses.
(4) Fuse cutouts at points C15, C16 and C17 with 10 ampere single-shot fuses.

If (1) is followed, manually operated switches could be placed at these points. If (2) is followed, the first shot of the line fuses will blow almost every time a transformer fuse blows, but since there will be one or two remaining shots, the line will remain in service. In this case, the lineman must examine the line fuses and replace the first shot after each such occurence. If (4) is used, it can be seen that the breaker will trip on any fault

in the section beyond the breaker. Temporary surges will be automatically removed, as the breaker will reclose. If the fault is permanent, the breaker will lock out. The lineman can then short out the breaker with a 20 ampere fuse. The particular branch fuse will then blow, the breaker can be reclosed, and the faulty line will be isolated.

Let us assume local conditions favor solution (3). Two-shot or three-shot 3 ampere fuses will then be installed at C15, C16, and C17. It would obviously be useless to install a fuse at C18, since there could be no coordination between C18 and C17. (Many operators favor solution (4)).

From the coordination table, fuse B20 should be a 25 ampere fuse, and fuse B10 a 25 ampere fuse, for proper coordination with a 2 ampere distribution transformer fuse; however, reclosers B7 and C7 are 25 ampere size, and from Plate "C" the largest fuse which can coordinate with this is a 10 ampere size. Hence B10 and C10 West must be made two- or three-shot with 10 ampere fuses.

The fuse at B20 can then be eliminated or replaced with a manual switch to provide for manual sectionalizing in case of trouble. The same applies to C12, except that two-shot 2 ampere fuses could be placed at C12, if desired.

The minimum current at C13 is 57 amperes,which is sufficient to blow a 10 ampere fuse at C10 West.

(12 ampere reclosers could also be placed at B10 and C10 West, if the investment were considered justified.)

The recloser at B9 has already been selected as 12 ampere.

Fuse A6 must be a 20 ampere size, and points A2 east and west must have 20 ampere fuses for proper coordination with the distribution transformer cutouts. These points may be made one-, or two-, or three-shot, according to the investment justified.

From Plate "C", 20 ampere fuses at A2 under a 194 ampere maximum fault will coordinate satisfactorily with the 35 ampere breaker at A1, B1, and C1. For 107 amperes, coordination is still satisfactory. For values between, however, the coordination is very close. If the fuse links are of the spring-type, or the cutout mechanically increases the gap when the fuse melts, coordination will probably be satisfactory.

Table (2)

Characteristics of Electro Type PB Relay

	Time in Seconds to Trip									
Times Current Tap Setting 1.5	1.3	2.1	4.0	5.3	6.6	7.9	9.3	10.8	12.0	13.3
2	0.9	1.7	2.5	3.4	4.2	5.0	5.9	6.7	7.5	8.4
3	0.7	1.2	1.7	2.3	2.8	3.4	3.9	4.5	5.0	5.5
5	0.5	0.9	1.2	1.7	2.0	2.4	2.8	3.2	3.6	4.0
10	0.4	0.7	0.9	1.2	1.5	1.8	2.1	2.3	2.6	2.9
20	0.3	0.5	0.7	0.9	1.1	1.3	1.5	1.8	2.0	2.2
30	0.2	0.4	0.6	0.8	1.0	1.2	1.3	1.5	1.7	1.9
50	0.2	0.3	0.5	0.7	0.8	1.0	1.1	1.3	1.5	1.6
Time Lever Setting	1	2	3	4	5	6	7	8	9	10

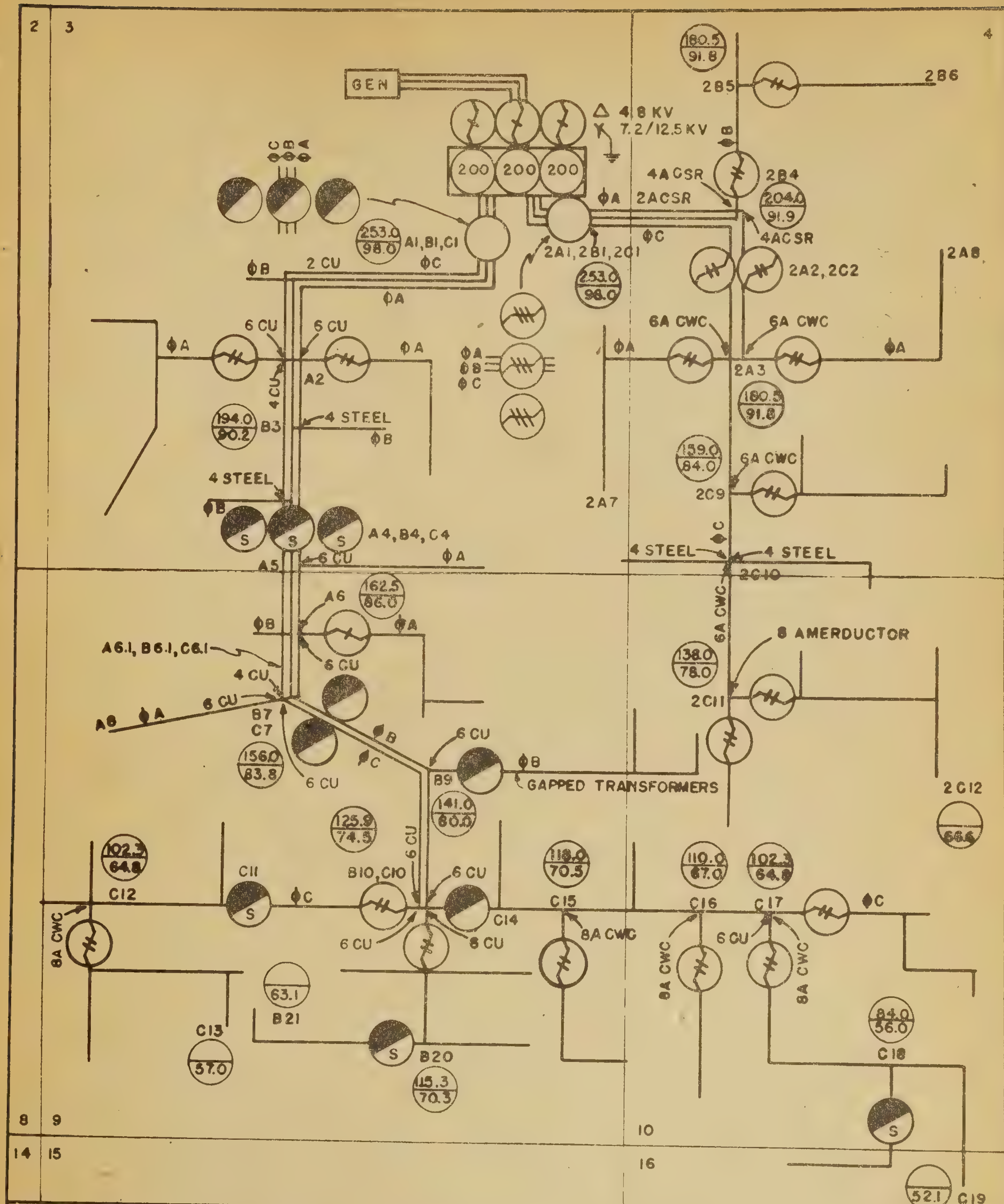
Taps are 4, 5, 6, 7, 10, 12, and 15 amperes.

Table (2) indicates the characteristics of the breaker relay in the plant. Since the current transformer is 200/5 ratio, one ampere on the relay is equal to 40 amperes in the main circuit. The maximum line-to-ground fault current referred to the supply side is 380 amperes, which melts the supply side fuse in about 3.9 seconds. The clearing time is around 4 seconds. Therefore, the relay time must be more than 4 seconds for 9.5 amperes. A number of tap and time settings will fulfill this condition. However, the relay should be set to "pick up" when the current in the lines is in excess of the minimum current which will melt the supply side fuse. Referring to the melting time curve, Plate "A", the relay must pickup at a current greater than $\frac{280}{40} = 7$ amperes. We should, therefore, use the 7 ampere relay tap. A time lever setting of 3 will provide more than the required 4 seconds for coordination with the supply side fuse at 380 amperes.

Now, by plotting characteristic curves such as those shown on plates "F" and "G" for the three phase and line-to-ground fault conditions respectively, it can be seen that the relay time lever setting 3 and tap setting 7 provide proper coordination over the entire range. A similar chart should be made for line-to-line faults. In plotting these curves all currents must be referred to the load side of the substation by formulae (13), (14), and (15).

The final circuit diagram, page 72 prepared as shown, giving selected devices and sizes, should be left for the guidance of the project operating personnel. It should be noticed that the fault current values are left on the final circuit diagram. These are indicated so that when future additions to the project are made, the entire set of values will not have to be recalculated.

(This example does not necessarily represent the most complete installation. For example, additional short-branch lines might be fused. The example is only for the purpose of method explanation.)



LARGE POWER LOADS				DATE	REVISIONS
POINT	INSTALLED KVA	DEMAND KVA	TYPE OF LOAD		
AG.I, B6.I, C6.I	60		CREAMERY		

CIRCUIT DIAGRAM

(Incomplete)

RURAL ELECTRIFICATION ADMINISTRATION

STATE	KEY	DETAIL	TOWN
SOME STATE	39	3 4 / 9 10 / 16	

TABLE (I) A

COORDINATION TABLE: SUPER #XX—ID FUSE LINKS.

MAXIMUM CURRENT FOR WHICH FUSE "B" WILL PROTECT FUSE "A"

FOR EXAMPLE ONLY
DO NOT USE FOR ACTUAL CASE

RATING, AMPS OF PROTECTING FUSE LINK "B"	NO. OF SHOTS	RATING IN AMPERES OF PROTECTED FUSE LINK "A"																
		1	2	3	5	8	10	15	20	25	30	40	45	50	75	85	95	100
1	1			50	75	110	120	140	200	300	400	600	900	1300	1700	2100	2400	2800
	2			25	50	75	110	120	140	200	300	400	600	900	1300	1700	2100	2400
	3				25	50	75	110	120	140	200	300	400	600	900	1300	1700	2100
2	1				60	90	110	140	200	300	400	600	900	1300	1700	2100	2400	2800
	2				25	60	90	100	140	200	300	400	600	900	1300	1700	2100	2400
	3					25	60	90	100	140	200	300	400	600	900	1300	1700	2100
3	1					30	90	125	200	300	400	600	900	1300	1700	2100	2400	2800
	2					25	60	90	120	200	300	400	600	900	1300	1700	2100	2400
	3						25	60	90	120	200	300	400	600	900	1300	1700	2100
5	1						60	100	175	300	400	600	900	1300	1700	2100	2400	2800
	2						25	60	100	175	300	400	600	900	1300	1700	2100	2400
	3							25	60	100	175	300	400	600	900	1300	1700	2100
8	1							75	150	300	400	600	900	1300	1700	2100	2400	2800
	2							40	75	150	300	400	600	900	1300	1700	2100	2400
	3								40	75	150	300	400	600	900	1300	1700	2100
10	1								100	250	400	600	900	1300	1700	2100	2400	2800
	2								50	100	250	400	600	900	1300	1700	2100	2400
	3									50	100	250	400	600	900	1300	1700	2100
15	1									150	300	600	900	1300	1700	2100	2400	2800
	2									75	150	300	600	900	1300	1700	2100	2400
	3										75	150	300	600	900	1300	1700	2100
20	1										200	500	900	1300	1700	2100	2400	2800
	2										100	200	500	900	1300	1700	2100	2400
	3											100	200	500	900	1300	1700	2100

U.S. DEPT OF AGRICULTURE — RURAL ELECTRIFICATION ADMINISTRATION — FEB. 1941

TABLE (1) B

COORDINATION TABLE: SUPER #XX—ID. FUSE LINKS.

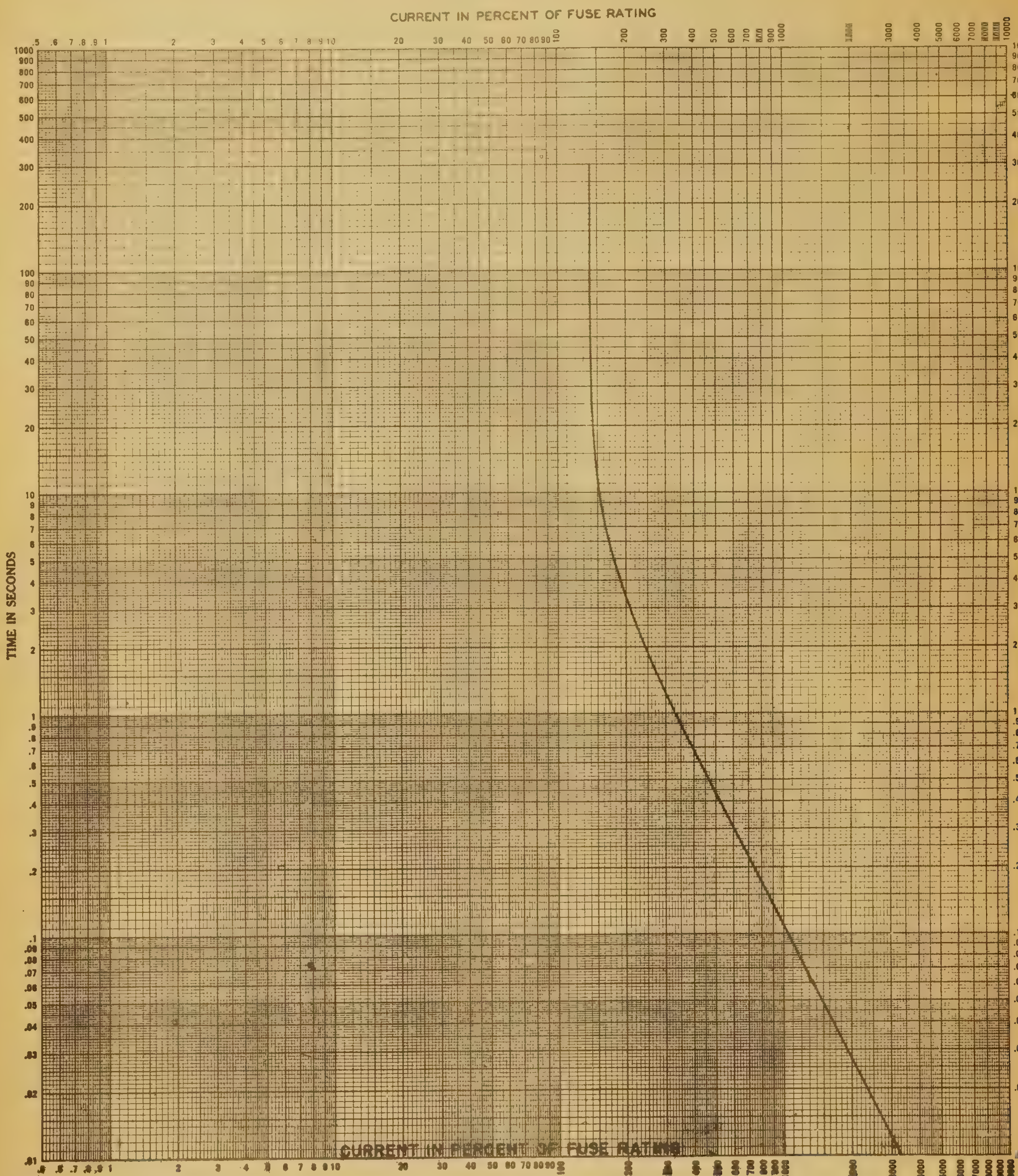
MAXIMUM CURRENT FOR WHICH FUSE "B" WILL PROTECT FUSE "A"

SOURCE — PROTECTED LINK "A" — PROTECTING LINK "B" — FAULT

FOR EXAMPLE ONLY
DO NOT USE FOR ACTUAL CASE

RATING, AMPS OF PROTECTING FUSE LINK "B"	NO. OF SHOTS	RATING IN AMPERES OF PROTECTED FUSE LINK "A"																
		1	2	3	5	8	10	15	20	25	30	40	45	50	75	85	95	100
25	1											300	700	1300	1700	2100	2400	2800
	2											150	300	700	1300	1700	2100	2400
	3												150	300	700	1300	1700	2100
30	1												500	1000	1700	2100	2400	2800
	2												250	500	1000	1700	2100	2400
	3													250	500	1000	1700	2100
40	1													700	1400	1800	2400	2800
	2													400	700	1400	1800	2400
	3														400	700	1400	1800
45	1														1000	1400	2400	2800
	2														500	1000	1400	2400
	3															500	1000	1400
50	1															1100	2200	2800
	2															600	1100	2200
	3																600	1100
75	1																1700	2400
	2																1000	1700
	3																	1000
85	1																	2100
	2																	1000
	3																	
95 & 100		NONE																

U.S. DEP'T OF AGRICULTURE — RURAL ELECTRIFICATION ADMINISTRATION — FEB. 1941



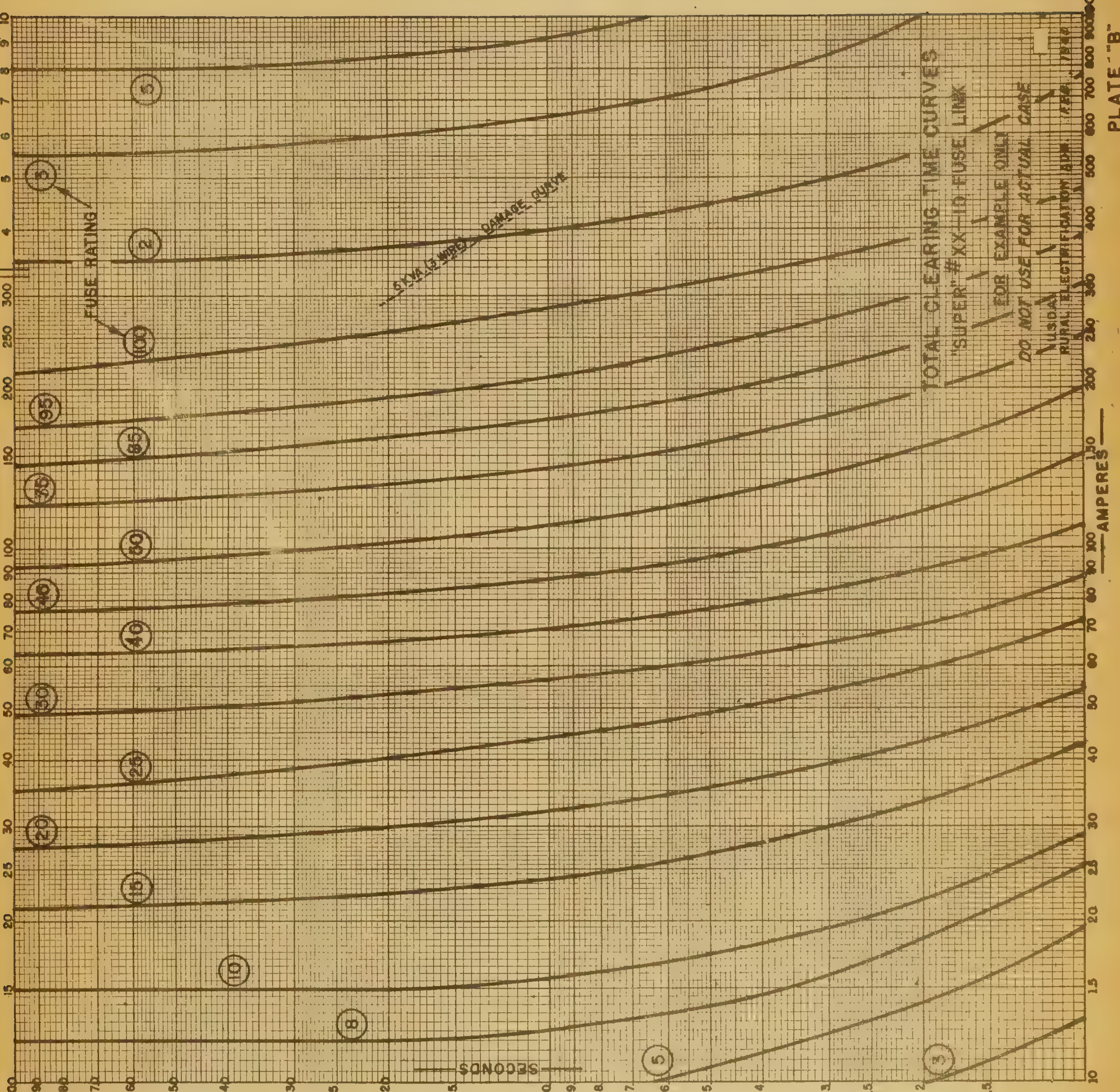
MELTING TIME
OF
PRESTO TYPE-K-POWER FUSE

FOR EXAMPLE ONLY. DO NOT USE IN ACTUAL CASE.

PLATE "A"

U.S. DEP'T OF AGRICULTURE
RURAL ELECTRIFICATION ADM.

FEB, 1941


TOTAL CLEARING TIME CURVES
"SUPER" #XX-10 FUSE LINK
FOR EXAMPLE ONLY
DO NOT USE FOR ACTUAL CASE
U.S.D.A.
RURAL ELECTRIFICATION ADM.
FUSE RATING
DAMAGE CURVE
AMPERES
SECONDS
PLATE "B"

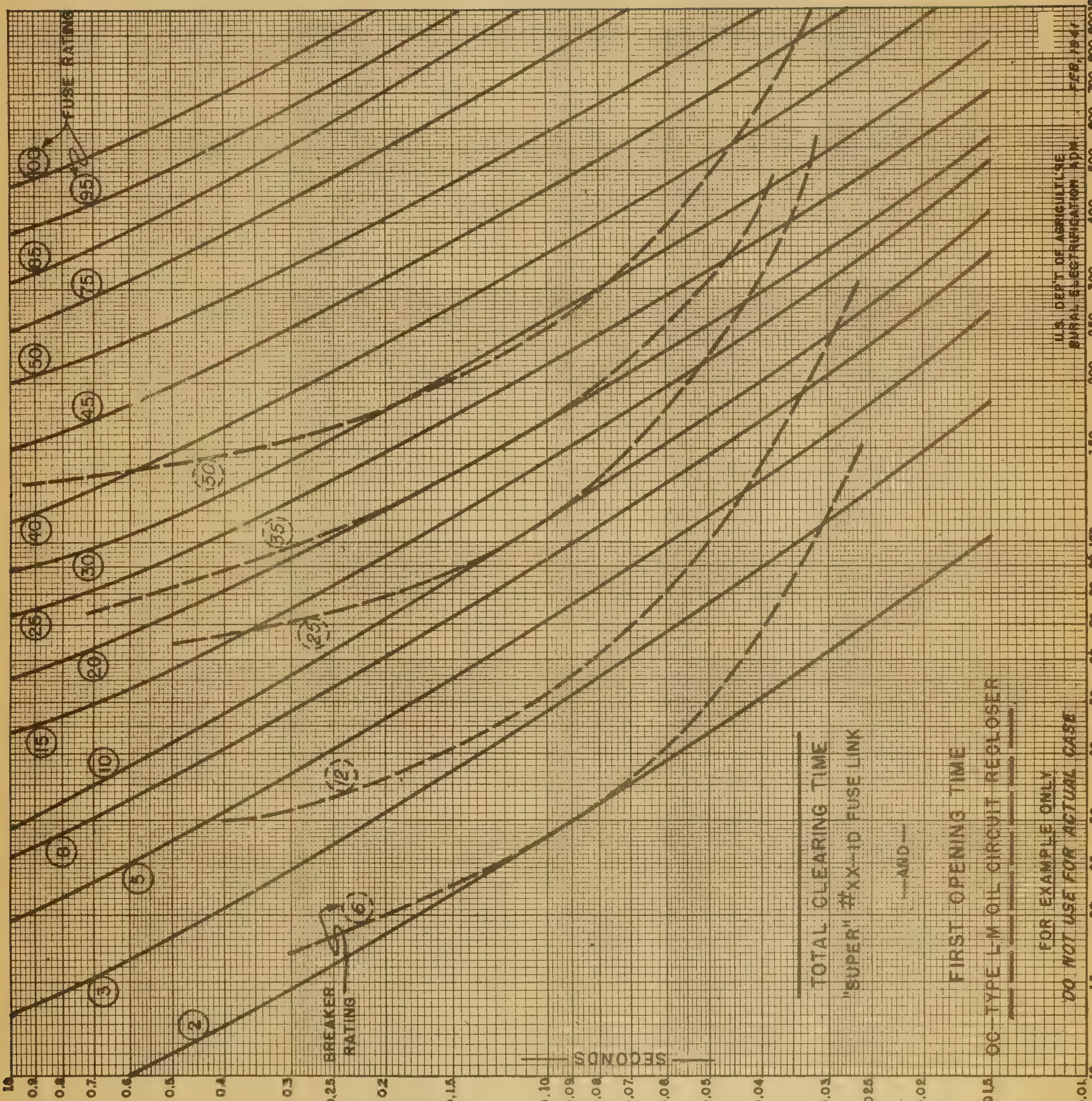

TOTAL CLEARING TIME
"SUPER" #XX-1D FUSE LINK
—AND—
FIRST OPENING TIME
OC-TYPE L-M OIL CIRCUIT RECLOSER
FOR EXAMPLE ONLY
DO NOT USE FOR ACTUAL CASE
FUSE RATING
BREAKER RATING
SECONDS
AMPERES
U.S. DEPT. OF AGRICULTURE
RURAL ELECTRIFICATION ADM.
FEB. 1941

PLATE "C"

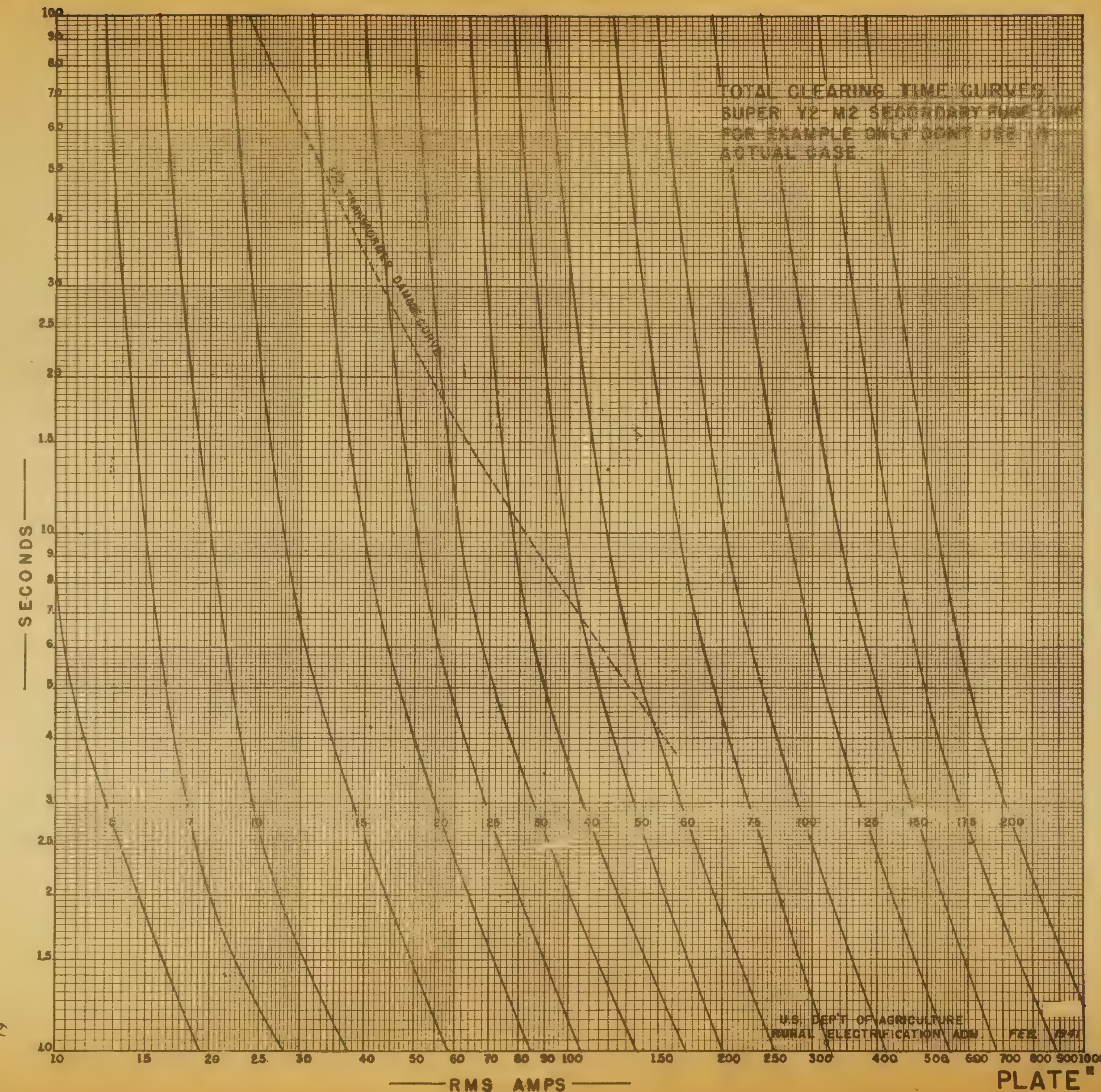
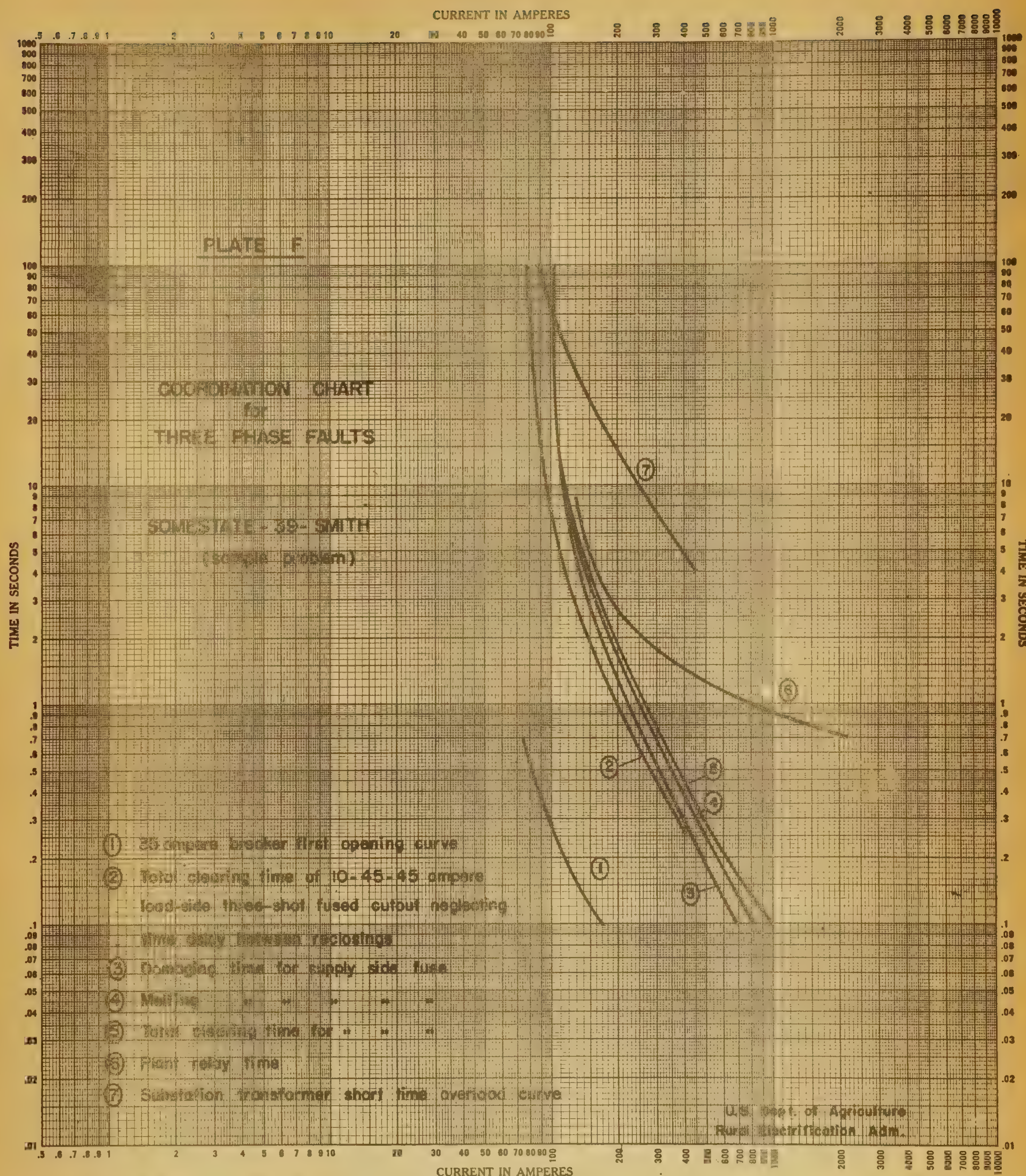

TOTAL CLEARING TIME CURVES
SUPER Y2-M2 SECONDARY FUSE LINK
FOR EXAMPLE ONLY DONT USE IN
ACTUAL CASE.
Y2 TRANSFORMER DAMAGE CURVE
6
7
10
15
20
25
30
40
50
60
75
100
125
150
175
200
SECONDS
RMS AMPS
U.S. DEPT OF AGRICULTURE
RURAL ELECTRIFICATION ADM. FEB. 1941

PLATE "E"



TIME-CURRENT CHARACTERISTIC CURVES

For .... Fuse Links. In ....

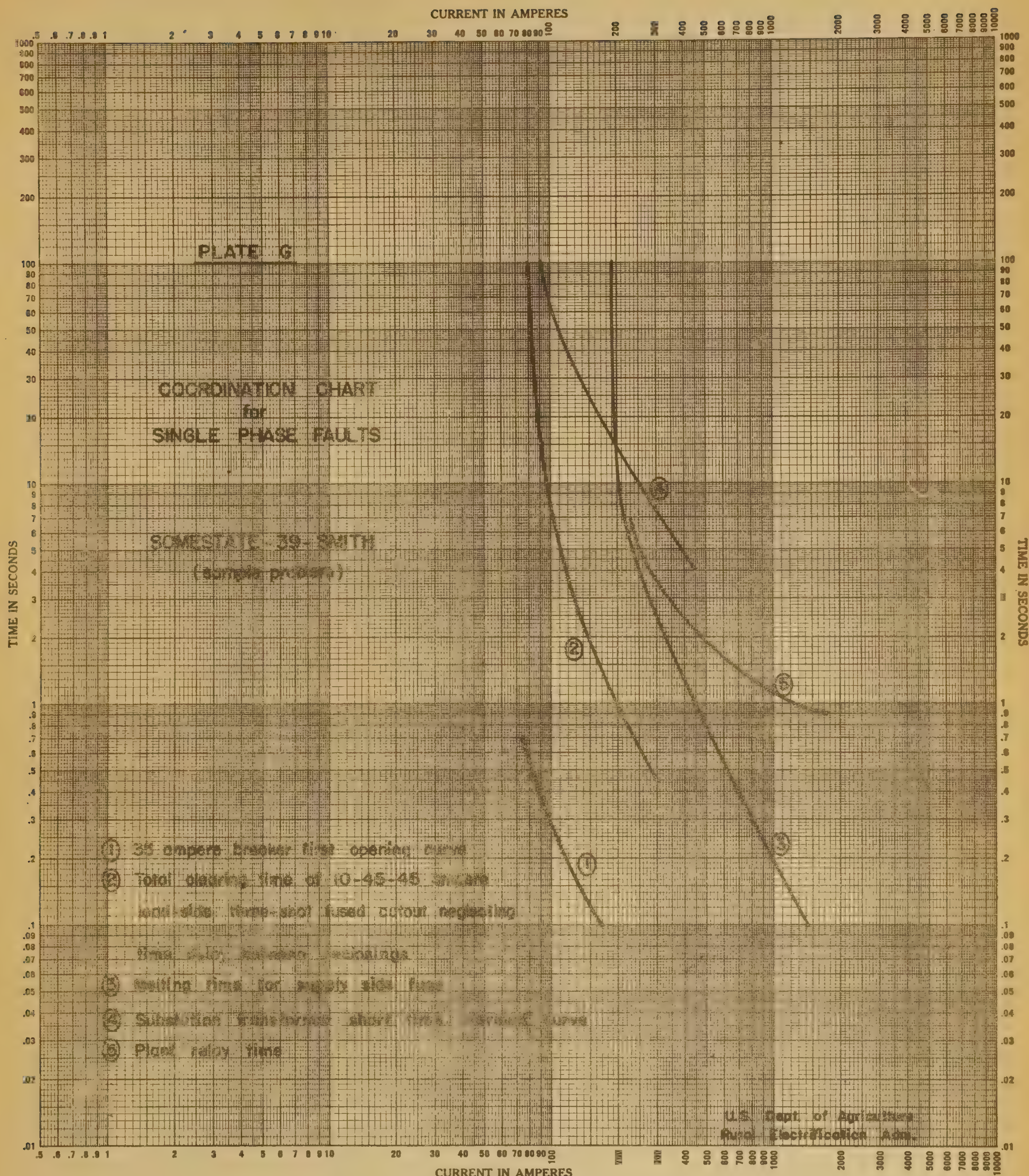
BASIS FOR DATA Standards .... Dated ....

1. Tests made at .... Volts a-c at .... p-f., Starting at 25C with no initial load ....

2. Curves are plotted to .... Test points so variations should be ....

No. ....

Date Dec. 1945



TIME-CURRENT CHARACTERISTIC CURVES

For .... Fuse Links. In ....

BASIS FOR DATA Standards .... Dated ....

1. Tests made at .... Volts a-c at .... p-f., Starting at 25C with no initial load ....

2. Curves are plotted to .... Test points so variations should be ....

No. ....

Date Dec. 1945

FORM TS-2R

U.S. DEP'T OF AGRICULTURE RURAL ELECTRIFICATION ADMINISTRATION	SECTIONALIZING STUDY	Sheet 1 of 4 sheets PROJECT Somestate 39 Smith
	SUBMITTED BY John Doe	DATE Sep. 1941
	CHECKED BY	DATE

	TYPE OF FAULT CALCULATED		
	LINE TO GRD.	LINE TO LINE	3 Ø
A — IMPEDANCE OF SOURCE			
1. PLANT			
(a) DIRECT AXIS TRANSIENT REACTANCE — FULL LOAD	16.3	16.3	16.3
(b) NEGATIVE SEQUENCE " — " "	10.1	10.1	0
(c) DIRECT AXIS TRANSIENT REACTANCE — MINIMUM "	48.9	48.9	48.9
(d) NEGATIVE SEQUENCE " " "	30.3	30.3	0
(e) EQUIVALENT PLANT REACTANCE FULL LOAD	8.8	15.2	16.3
(f) EQUIVALENT PLANT REACTANCE MINIMUM LOAD	26.4	45.7	48.9
2. TIE LINE AND TIE LINE TRANSFORMERS			
(g) RESISTANCE REFERRED TO LOAD VOLTAGE	3.7	6.3	5.5
(h) REACTANCE " " " "	9.1	15.8	13.7
3. TOTAL			
(i) MAXIMUM LOAD 1. RESISTANCE EQUAL (g)	3.7	6.3	5.5
2. REACTANCE " (e) + (h)	17.9	[illegible]	[illegible]
(j) MINIMUM LOAD 1. RESISTANCE " (g)	3.7	6.3	5.5
2. REACTANCE (f) + (h)	35.5	[illegible]	[illegible]
4. FOR LARGE SUPPLY SYSTEM ONLY			
(k) MAXIMUM LOAD REACTANCE			
(l) MINIMUM " "			
B — IMPEDANCE OF SUBSTATION			
(m) Z_T	10.2	11.8	[illegible]
(n) R_T	2.0	2.4	2.0
(o) X_T	10.0	11.5	10.0
C — TOTAL IMPEDANCE OF SOURCE AND SUBSTATION			
(p) MAXIMUM CONDITIONS			
1. $R = (n) + (i_1)$	5.7	8.7	7.5
2. $X = (o) + (i_2)$ or (k)	27.9	42.5	40.0
(q) MINIMUM CONDITIONS			
1. $R = (n) + (j_1)$	5.7	8.7	7.5
2. $X = (o) + (j_2)$ or (l)	45.5	73.0	72.6

FORM TS-3

U.S. DEPARTMENT OF AGRICULTURE
RURAL ELECTRIFICATION ADMINISTRATION

SECTIONALIZING STUDY

SHEET 2 OF 4 SHEETS

PROJECT Somestate-39-Smith

SUBMITTED BY John Doe DATE Feb. 1941 CHECKED BY ______ DATE ______

r	s	t	u	v	w	x.	y	z	aa	ab	ac	ad	ae	af	ag	ah
POINT	PRECEDING POINT ON LINE TOWARD SUBSTATION	MILES FROM PREVIOUS POINT ON LINE TOWARD SUBSTATION	COPPER CONDUCTIVITY SIZE, SECTION FROM PREVIOUS POINT	TYPE OF FAULT CALCULATED	RESISTANCE "R", SECTION FROM PREVIOUS POINT	RESISTANCE "R", BACK TO SUBSTATION	FOR MAX. CONDITION, TOTAL RESISTANCE TO SOURCE = $x + p_1$	FOR MIN. CONDITION, TOTAL RESIST. TO SOURCE = y + FAULT RESIST.	REACTANCE "X", SECTION FROM PREVIOUS POINT	REACTANCE "X", BACK TO SUBSTATION	FOR MAX. CONDITION, TOTAL REACTANCE TO SOURCE = $ab + p_2$	FOR MIN. CONDITION, TOTAL REACTANCE TO SOURCE = $ab + q_2$	FOR MAX. CONDITION, TOTAL IMPEDANCE TO SOURCE = $\sqrt{y^2 + ac^2}$	FOR MIN. CONDITION, TOTAL IMPEDANCE TO SOURCE = $\sqrt{z^2 + ad^2}$	MAX. CURRENT "I" = $\frac{\text{VOLTAGE}}{ae}$	MIN. CURRENT "I" = $\frac{\text{VOLTAGE}}{af}$
A1							5.7	45.7			27.9	45.5	28.5	64.4	253.0	112.0
A2	A1	6	#2		6.0	6.0	11.7	51.7	7.3	7.3	35.2	52.8	27.1	74.0	194.0	97.3
A6	A2	4	#4	LINE - TO - GROUND	6.5	12.5	18.2	58.2	5.2	12.5	40.4	58.0	44.3	82.2	162.5	87.6
B7	A6	1	#4		1.6	14.1	19.8	59.8	1.3	13.8	41.7	59.3	46.1	84.0	156.0	85.7
B9															141.0*	80.0*
C10	B7	4.5	#6		11.0	25.1	30.8	70.8	6.6	20.4	48.3	65.9	57.3	96.6	125.9	74.5
C12	C10	5	#6		12.3	37.4	43.1	83.1	7.3	27.7	55.6	73.2	70.4	111.0	102.3	64.8
C13	C12	4	#8		15.0	52.4	58.1	98.1	6.2	33.9	61.8	79.4	84.9	126.3	84.9	57.0
B20	C10	2	#6		4.9	30.0	35.7	75.7	2.9	23.3	51.2	68.8	62.4	102.4	115.3	70.3
B21	B20	3	#8		11.2	41.2	46.9	86.9	4.7	28.0	55.9	73.5	73.0	114.0	98.6	63.1
C15			#6												118.0*	70.5*

*Estimated

FORM TS-3

U.S. DEPARTMENT OF AGRICULTURE
RURAL ELECTRIFICATION ADMINISTRATION

SECTIONALIZING STUDY

SHEET 3 OF 4 SHEETS

—— PROJECT ——
Somestate-39-Smith

SUBMITTED BY John Doe, DATE Feb. 1941 CHECKED BY ________, DATE ________

r	s	t	u	v	w	x	y	z	aa	ab	ac	ad	ae	af	ag	ah
POINT	PRECEDING POINT ON LINE TOWARD SUBSTATION	MILES FROM PREVIOUS POINT ON LINE TOWARD SUBSTATION	COPPER CONDUCTIVITY SIZE, SECTION FROM PREVIOUS POINT	TYPE OF FAULT CALCULATED	RESISTANCE "R", SECTION FROM PREVIOUS POINT	RESISTANCE "R", BACK TO SUBSTATION	FOR MAX. CONDITION, TOTAL RESISTANCE TO SOURCE = $x + p_1$	FOR MIN. CONDITION, TOTAL RESIST TO SOURCE = y + FAULT RESIST.	REACTANCE "X", SECTION FROM PREVIOUS POINT	REACTANCE "X", BACK TO SUBSTATION	FOR MAX. CONDITION, TOTAL REACTANCE TO SOURCE = $ab + p_2$	FOR MIN. CONDITION, TOTAL REACTANCE TO SOURCE = $ab + q_2$	FOR MAX. CONDITION, TOTAL IMPEDANCE TO SOURCE = $\sqrt{y^2 + ac^2}$	FOR MIN. CONDITION, TOTAL IMPEDANCE TO SOURCE = $\sqrt{z^2 + ad^2}$	MAX. CURRENT "I" = $\frac{VOLTAGE}{ae}$	MIN. CURRENT "I" = $\frac{VOLTAGE}{af}$
C16															110.0*	67.0
C17	C10	5	#6		12.3	37.4	43.1	83.1	7.3	27.7	55.6	73.2	70.4	111.0	102.3	64.8
C18															84.0*	56.0*
C19	C17	7	#8		26.2	63.6	69.3	109.3	10.9	38.6	66.5	84.1	96.0	138.0	75.0	52.1
2A2	2A1	4	#4	LINE - TO - GROUND	6.5	6.5	12.2	52.2	5.2	5.2	33.1	50.7	35.3	72.7	204.0	99.0
2B4	2A1															
2B5	2B4	2	#6		4.9	11.4	17.1	57.1	2.9	8.1	36.0	53.6	39.9	78.4	180.5	91.8
2A3	2A2	2	#6		4.9	11.4	17.1	57.1	2.9	8.1	36.0	53.6	39.9	78.4	180.5	91.8
269															159.0*	84.0*
2C11	2A3	5	#6		12.3	23.7	29.4	69.4	7.3	15.4	43.3	60.9	52.3	92.4	138.0	78.0
2C12	2C11	4	#8		15.0	38.7	44.4	84.4	6.2	21.6	49.5	67.1	66.6	108.0	108.0	66.6

*Estimated

FORM TS-3

U.S. DEPARTMENT OF AGRICULTURE
RURAL ELECTRIFICATION ADMINISTRATION

SECTIONALIZING STUDY

SHEET 4 OF 4 SHEETS

PROJECT: Somestate 39 Smith

SUBMITTED BY John Doe DATE Feb. 1941 CHECKED BY DATE

r	s	t	u	v	w	x.	y	z	aa	ab	ac	ad	ae	af	ag	ah
POINT	PRECEDING POINT ON LINE TOWARD SUBSTATION	MILES FROM PREVIOUS POINT ON LINE TOWARD SUBSTATION	COPPER CONDUCTIVITY SIZE, SECTION FROM PREVIOUS POINT	TYPE OF FAULT CALCULATED	RESISTANCE "R", SECTION FROM PREVIOUS POINT	RESISTANCE "R", BACK TO SUBSTATION	FOR MAX. CONDITION, TOTAL RESISTANCE TO SOURCE = $x + p_1$	FOR MIN. CONDITION, TOTAL RESIST TO SOURCE = y + FAULT RESIST.	REACTANCE "X", SECTION FROM PREVIOUS POINT	REACTANCE "X", BACK TO SUBSTATION	FOR MAX. CONDITION, TOTAL REACTANCE TO SOURCE = $ab + p_2$	FOR MIN. CONDITION, TOTAL REACTANCE TO SOURCE = $ab + q_2$	FOR MAX. CONDITION, TOTAL IMPEDANCE TO SOURCE = $\sqrt{y^2 + ac^2}$	FOR MIN. CONDITION, TOTAL IMPEDANCE TO SOURCE = $\sqrt{z^2 + ad^2}$	MAX. CURRENT "I" = $\frac{\text{VOLTAGE}}{ae}$	MIN. CURRENT "I" = $\frac{\text{VOLTAGE}}{af}$
A1				← 3 phase →			7.5	7.5			40.0	72.6	40.7	73.0	177.0	98.7
A2	A1	6	#2		5.2	5.2	12.7	12.7	4.6	4.6	44.6	77.2	46.5	78.4	151.0	91.9
B7	A2	5	#4		6.8	12.0	19.5	19.5	4.0	8.6	48.6	81.2	52.5	83.4	137.0	86.4
2A2	2A1	4	#4		5.4	5.4	12.9	12.9	3.2	3.2	43.2	75.8	45.1	77.0	160.0	93.5
2A1				Line-to-Line			8.7	8.7			42.5	73.0	43.3	73.5	166.0	98.0
A2	A1	6	#2		6.0	6.0	14.7	14.7	5.3	5.3	47.8	78.3	50.0	79.7	144.0	90.2
B7	A2	5	#4		7.9	13.9	22.6	22.6	4.6	9.9	52.4	82.9	57.0	86.0	126.0	83.8
B10	B7	4.5	#6		11.3	25.2	33.9	33.9	4.3	14.2	56.7	87.2	66.1	93.6	109.0	76.9
2A2	2A1	4	#4		6.2	6.2	14.9	14.9	3.7	3.7	46.2	76.7	48.5	78.3	148.0	91.9
2A3	2A2	2	#6		5.0	11.2	19.9	19.9	1.9	5.6	51.8	78.6	55.5	81.0	130.0	88.8

FORM TS-4R

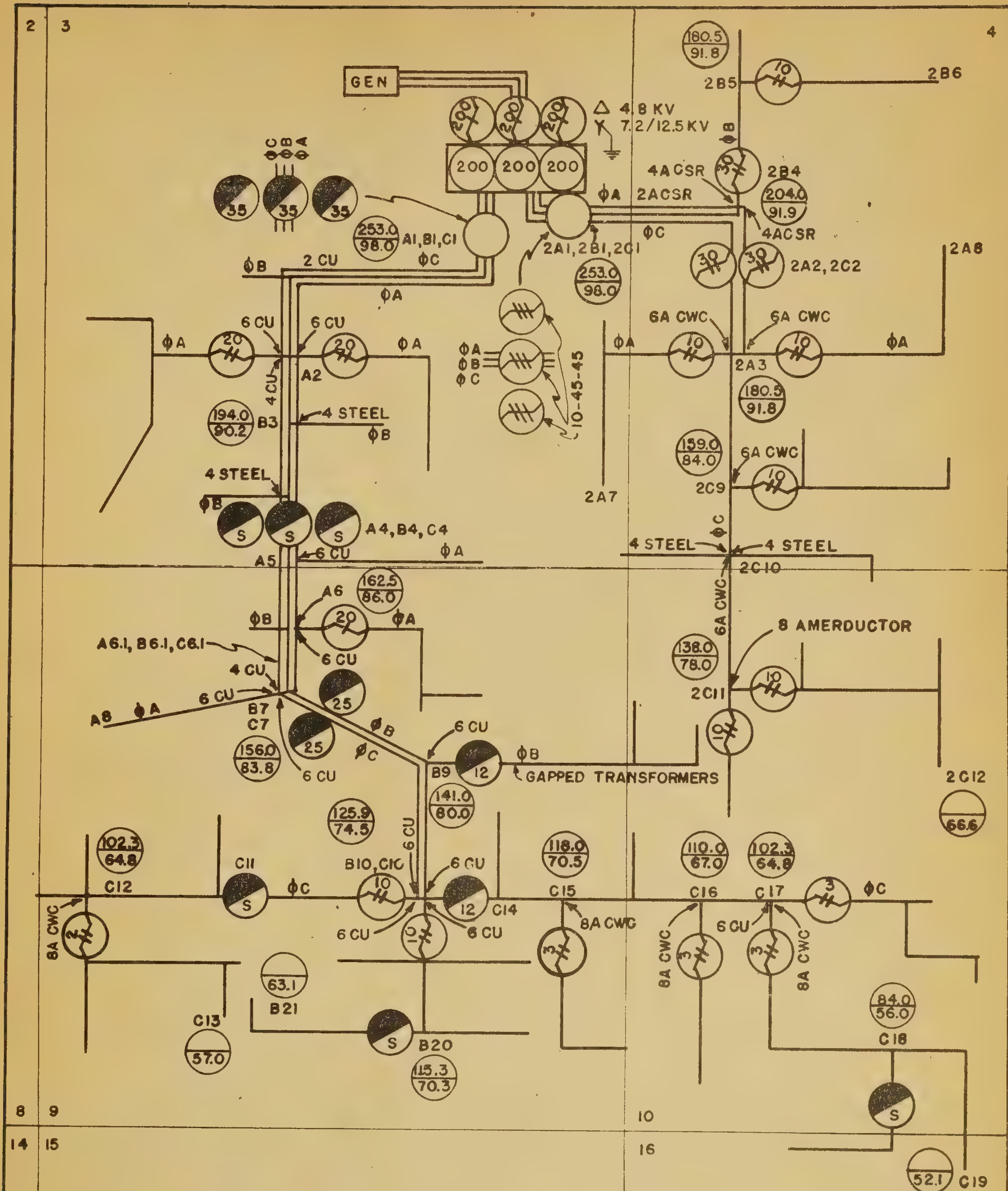
U.S. DEP T OF AGRICULTURE RURAL ELECTRIFICATION ADMINISTRATION	SECTIONALIZING STUDY	Sheet 1 of 1 sheets PROJECT Somestate 39 Smith
	SUBMITTED BY John Doe	DATE Feb., 1941
	CHECKED BY	DATE

This Study is based on the use of the following makes of Sectionalizing Equipment:

	BREAKERS	FUSE LINKS
1. Substation — Supply Side		Presto-Type "K"
2. Substation — Load Side	OC-Type IM	Super XX-ID
3. Lines	" " "	" " "

POINT	MAX. LOAD CURRENT	MAX. FAULT CURRENT	MIN. FAULT CURRENT*	PRESENT DEVICE TYPE	PRESENT DEVICE DISPOSITION	DEVICE TO BE INSTALLED TYPE	DEVICE TO BE INSTALLED RATING	REMARKS
Substation		Supply	Side			1-shot	200A	
A1	4.2	253.0	83.8			Breaker	35A	
B1	5.5	253.0	83.8			"	"	
C1	5.5	253.0	83.8			"	"	
2A1	3.0	253.0	91.9			3-shot	10-45-45	
2B1	3.0	253.0	91.9			" "	" " "	
2C1	4.0	253.0	91.9			" "	" " "	
2B4	0.7	204.0	91.8			2-shot	30A	
2B5	0.4	180.5	—			2-shot	10A	
2A2	3.0	204.0	91.8	None		2-shot	30A	
2C2	3.9	204.0	78.0			2-shot	30A	
2A3	0.6	180.5	—			2-shot	10A	In lines East and West
2C9	0.6	159.0	—			2-shot	10A	
2C11	0.3	138.0	—			2-shot	10A	In tap South
2C11	0.7	138.0	66.6			2-shot	10A	In tap East
A2	0.8	194.0	—			2-shot	20A	In lines East & West
A6	0.6	162.5	—			1-shot	20A	
B7	3.9	156.0	74.5			Breaker	25A	
C7	4.2	156.0	74.5			"	25A	
B9	0.8	141.0	--			"	12A	
B10	1.3	125.9	63.1			2-shot	10A	
C10	1.7	125.9	64.8			2-shot	10A	In Line West
C12	0.7	102.3	57.0			2-shot	2A	
C10	3.6	125.9	64.8			Breaker	12A	
C15	0.6	118.0	—			2-shot	3A	
C16	0.4	110.0	—	None		2-shot	3A	
C17	0.6	102.3	—			2-shot	3A	In tap East
C17	1.3	102.3	52.1			2-shot	3A	In Line South

* MINIMUM FAULT CURRENT AT END OF CONTROLLED SECTION.



LARGE POWER LOADS			
POINT	INSTALLED KVA	DEMAND KVA	TYPE OF LOAD
A6.1, B6.1, C6.1	60		CREAMERY

DATE	REVISIONS

CIRCUIT DIAGRAM

RURAL ELECTRIFICATION ADMINISTRATION

STATE	KEY	DETAIL	TOWN
SOME STATE	39	3 4 / 9 10 / 16	

Graphical Method of Calculating Fault Currents on R.E.A. Lines

A graphical method for calculating fault currents has been devised by Mr. Frank Linder. This is based on the methods described above, but uses graphical means instead of analytical. The graphical method may save time, while it also offers a visual picture and permanent record of the fault currents, and provides a simple method for calculating such currents on new branch lines. The graphical method is sufficiently accurate for R.E.A. system purposes. If the graphical method is used, Form TS-4 is not necessary.

Information Required

Data as shown on Form TS-5R (Page 3) should be obtained no matter what method of calculation is used. In particular, for graphical calculation purposes, the following information is necessary:

1. Total resistance and total reactance, for both the maximum and minimum fault current conditions, on the load side of the REA supply substation or at the metering point. It is necessary to know these resistance and reactance values for three phase, line-to-line, and line-to-ground faults and they must be referred to the line-to-ground voltage of the system. See Chap. II, discussion on source impedances, and form TS-2R.

2. Location of sectionalizing points on a circuit diagram of the system.

3. Phasing, mileages, and wire sizes between sectionalizing points and from the last sectionalizing points to the end of the most distant tap.

Description of Current Diagrams

The fault current calculations are made on current diagrams. Separate current diagrams are used for each fault current study; and these are made a part of the sectionalizing study file. Current diagrams are available for three phase, line-to-line, and line-to-ground faults on 7200 volt neutral grounded systems built to REA specifications. The 7200 volt current diagrams can be used for other system voltages, as explained on page 74.

Referring to one of the attached current diagrams, notice that the background of the diagram is a rectangular coordinate system with resistance in ohms along the horizontal axis and reactance in ohms along the vertical axis. Superimposed upon the coordinate system, there is a series of

cocentric quarter circles, each circle indicating a value of short circuit current. Note that the current diagram is really the first quadrant of a current vector diagram with the line-to-ground voltage as the base voltage. Fault currents can be read on the circle at the intersection of the total resistance and the total reactance values of the circuit.

In the lower right-hand corner, there is a group of scales called "mileage scales," each scale representing a different copper equivalent conductor size. The length of line in miles is marked along each scale, starting from zero on the left end of the scale. The position of each mileage scale on the diagram and the calibration of each scale is governed by the per mile resistance and reactance values of lines built to REA specifications for each conductor size. The mileage scales are based on average values of resistance and reactance for the various types of conductor. The scale to which each mileage scale was drawn is the same as the scale of the rectangular coordinate system on the main part of the current diagram.

There are two current diagrams for line-to-ground faults, numbered 1 and 2, Current diagram No. 2 is a continuation of diagram No. 1 for use when it is found that the range of diagram No. 1 is not large enough to determine fault currents at all desired points on a system. There is only one current diagram each for three phase, and line-to-line faults, which will cover the range of three phase and line-to-line fault currents on REA systems.

Use of Data Sheet

Attached there is a copy of Form DS-89 which should be used for tabulating the data necessary to plot the fault current points on the diagram, and for tabulating the maximum and minimum fault currents. Each sectionalizing point on the system, and the most distant points beyond the last sectionalizing devices, should be designated on a circuit diagram in accordance with Eng. Memo 154. Then the data necessary to plot the points on the current diagram should be tabulated in the first five columns of the form. After the points have been plotted on the current diagram, the fault currents at 7200 volts phase to ground as read on the current diagram can be tabulated in the sixth and seventh columns. Columns eight and nine are to be used only when the system voltage is other than 7.2/12.5 KV. The columns on the right half of the form are the same as those on the left half of the form; in other words, the right half is a continuation of the left half.

Calculation of Fault Currents When System Voltages is Not 7.2/12.5 KV By Using Current Values Determined From 7200 Volt Current Diagrams

The current diagrams are all based on a line-to-ground voltage of 7200 volts; therefore, fault currents on 7.2/12.5 KV systems can be read directly from the current diagrams. For systems whose line-to-ground voltage is 6900 volts or any other voltage except 7200 volts, fault currents as read on the current diagrams must be corrected to the actual line-to-ground voltage.

The fault current at any location on a system is directly proportional to the line-to-ground voltage. Suppose a fault current study is being made on a system whose voltage is 6.9/11.9 KV. The fault currents as read on the

7200 volt three phase, line-to-line, and line-to-ground current diagrams must be multiplied by $\frac{6900}{7200}$ in order to obtain the actual fault current values.

The last two columns, columns eight and nine, on the data sheet are for use in tabulating the actual fault currents. If the line-to-ground voltage is not 7200 volts, multiply the fault current values read on the current diagrams, which have been tabulated in columns six and seven, by $\frac{\text{actual line-to-ground voltage}}{7200}$ and tabulate the actual fault currents in columns eight and nine.

Procedure For Calculating Short Circuit Currents on Current Diagrams

1. On the current diagram for the type of fault being calculated, locate the point for the total impedance of the source and REA substation by laying off the resistance along the horizontal scale and the reactance along the vertical scale. Locate the total impedance for both the maximum and minimum conditions. For the minimum condition on line-to-ground faults, be sure to add in the assumed value of fault resistance. Mark these two points $S_{max.}$ and $S_{min.}$

   By using two triangles or a drafting machine, draw a line from $S_{max.}$ and $S_{min.}$ to the right parallel to the mileage scale for the conductor size in the first section of line away from the substation. The easiest method of drawing this line is to lay the hypotenuse of a 30 - 60 degree triangle along the proper mileage scale. Then lay a ruler along the base of the triangle and slide the triangle up along the ruler until the hypotenuse of the triangle is on point $S_{max.}$ or $S_{min.}$ Draw the desired line along the hypotenuse of the triangle.

   Please note that an extended portion of each mileage scale has been placed in the right hand margin of the form, which will aid in lining up the triangle along the desired mileage scale.

3. Using a compass, or dividers, and the mileage scale for the proper conductor size, set the instrument to the number of miles from the substation to the first sectionalizing point. Lay this distance off from $S_{max.}$ and $S_{min.}$ along the line drawn in step two. Letter these points the same as the corresponding point on the circuit diagram is designated.

4. Read the short circuit currents on the circles.

5. Repeat the above procedure for the next sectionalizing point farther out on the system, except that the mileage distance should be laid off from the last points plotted instead of from $S_{max.}$ and $S_{min.}$ If the next section is of a different conductor size, draw a new line on the diagram, parallel to the proper mileage scale. Repeat until all points on the system, at which short circuit current values are desired, have been plotted on the diagram.

6. For some systems, all line-to-ground fault current points can be plotted on current diagram No. 1. On other systems, the fault current points located a considerable distance from the substation will fall off of current diagram No. 1, in which case, current diagram No. 2 should be used. The last point that will fall on diagram No. 1 should be located on diagram No. 2 at the intersection of the resistance and reactance values for the point which can be read on the resistance and reactance scales of diagram No. 1. Then continue plotting points on diagram No. 2 as before. In the case of three phase and line-to-line faults, all fault current points can be plotted on one diagram.

Mileage Scales Not Given on Current Diagram

Mileage scales are given on the current diagram for the most commonly used conductor sizes. In cases where there is not a mileage scale for the conductor installed on the distribution line, a mileage scale can easily be drawn on the diagram. It is necessary to know the resistance and reactance of the line in ohms per mile for the type of conductor used and for the type of fault being calculated. Pick any convenient point several inches to the left of the mileage scales on the diagram. From this point, using the resistance scale on the diagram, lay off a distance to the right equal to the resistance of one mile of the line. From the point just located, lay off a distance vertically upward, equal to the reactance of one mile of the line. There will now be two legs of a right triangle, the hypotenuse of which is equal to the impedance of one mile of the line. Draw the hypotenuse and extend it upward to the right. The line drawn will be the mileage scale desired. Calibrate the scale in miles by marking off distances on the scale equal to the length of the hypotenuse of the small triangle. In order to obtain greater accuracy in plotting the mileage scale, it is suggested that ten times the per mile resistance and reactance values be used in laying off the triangle as explained above. Then subdivide the hypotenuse into ten parts.

Steel Conductors - The impedance of a line consisting of steel conductor varies considerably depending upon the amount of current flowing in the line, which makes it impossible to use one mileage scale for all values of fault current. The single phase impedance of a No. 4 or No. 6 Amersteel type 3S-130 conductor line carrying 100 amperes is approximately twice the impedance of the same line carrying a current of one ampere. However, for all values of current, the ratio of resistance to reactance for either a No. 4 or No. 6 steel conductor line is approximately the same as the ratio of resistance to reactance of No. 11 copper equivalent conductor. In other words, the slope of the mileage scales for these steel conductors would be the same as the slope of the No. 11 copper equivalent mileage scale on the current diagrams, which means the mileage scale No. 11 on the current diagram can be used for steel conductor lines provided that the calibration of the scale is corrected for steel conductor.

The procedure for plotting line-to-ground fault current points on the current diagram for steel conductor lines by correcting the mileage scale for No. 11 copper equivalent conductor is as follows:

1. From the current diagram determine the maximum (or minimum) fault current at the beginning of the section of steel conductor line in question.

Knowing the fault current at the beginning of the section, estimate the value of maximum (or minimum) fault current which will occur at the end of the section or at the fault point of the steel conductor section. In other words, estimate the fault current flowing in the steel conductor.

2. Select the proper "mileage correction factor" from the following table for the fault current at the end of the section as determined in step one. Interpolate if necessary.

MILEAGE CORRECTION FACTORS FOR AMERSTEEL STEEL TYPE 3S-130 CONDUCTORS (LINE-TO-GROUND FAULTS)

Line Fault Current In Amperes	Mileage Correction Factor For #4 B.W.G. Conductor Size	Mileage Correction Factor For #6 B.W.G. Conductor Size
10	1.23	1.58
20	1.39	1.67
30	1.62	1.95
40	1.85	2.45
50	2.06	2.96
60	2.25	3.06
70	2.25	3.00
80	2.20	2.94
90	2.16	2.85
100	2.12	2.74

For current values above 100 amperes use mileage correction factors for 100 amperes.

3. Multiply the "mileage correction factor" by the actual length of steel conductor line in the section. This gives a corrected mileage which can be plotted from the No. 11 copper equivalent scale.

4. Plot the fault current point on the current diagram for the end of the section of steel conductor by using the mileage scale for No. 11 copper equivalent conductor and the corrected length of the section as determined in step 3 above.

If you are unable to estimate the fault current at the end of the section, select a "mileage correction factor" for the first or second value of current listed in the table which is smaller than the fault current at the beginning of the section. Plot the fault current point for the end of the section, and from the current diagram read the value of fault current. Check to see if the proper "mileage correction factor" was used. If not, select a "mileage correction factor" for the new value of fault current at the end of the section and replot the point. Repeat until the assumed value and the actual fault current are approximately the same value.

A "mileage correction factor" is the ratio of the impedance of steel conductor for a given value of fault current to the impedance of No. 11 copper equivalent conductor. The correction factors given in the table are for line-to-ground faults on line consisting of Amersteel conductor. Some makes of steel conductor have slightly different electrical characteristics;

however, the correction factors given in the table can be used for all makes of steel conductors approved for use on REA systems. A fuse or breaker, which will operate satisfactorily on the bases of fault current calculations made as explained above, will be satisfactory on a line consisting of any one of the approved types of steel conductor.

Suggestion

A separate current diagram should be used for each substation on the system. In cases where one substation serves a large number of miles of line, and there are a large number of sectionalizing points, it is suggested that separate current diagrams be used for each one of the main feeders from the substation, in order to prevent confusion which may result from too many points on the same current diagram.

On the following pages there are copies of the data sheet, Form DS-89, and current diagrams for calculating three phase, line-to-line, and line-to-ground fault currents, Forms DS-90, DS-91, DS-92, and DS-93. Also attached there is a sample problem and the complete graphical solution for determining the line-to-ground short circuit currents at the various sectionalizing points.

Form DS-89

U. S. DEPARTMENT OF AGRICULTURE RURAL ELECTRIFICATION ADMINISTRATION	SECTIONALIZING STUDY Sheet Of Sheets	Project Designation
Prepared by: Date	Checked by Date	System Line-To-Gr. Voltage Volts

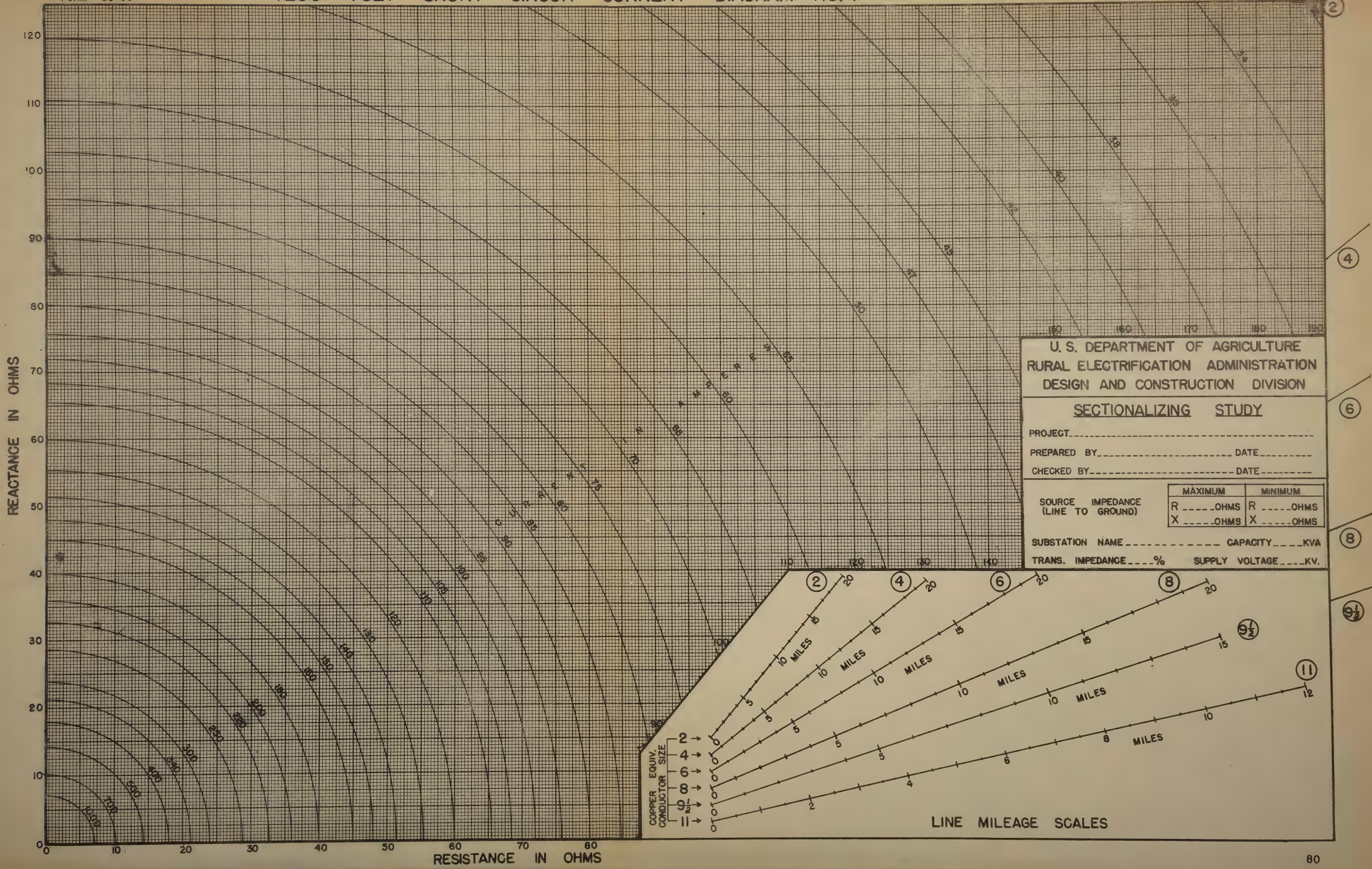
1 Point	2 Preceding Point On Line Toward Substation	3 Miles from Previous Point On Line Toward Substation	4 Copper Conductivity Size Section From Previous Point	5 Type of Fault Calculated	6 Maximum Fault Current Read on Current Diagram (7200 Volts Line-To-Ground)	7 Minimum Fault Current Read on Current Diagram (7200 Volts Line-To-Ground)	8 Actual Maximum Fault Current Col. No.5x $\frac{\text{Line-To-Gr. Volts}}{7200}$	9 Actual Minimum Fault Current Col. No.7x $\frac{\text{Line-To-Gr. Volts}}{7200}$

1 Point	2 Preceding Point on Line Toward Substation	3 Miles From Previous Point On Line Toward Substation	4 Copper Conductivity Size Section From Previous Point	5 Type of Fault Calculated	6 Maximum Fault Current Read on Current Diagram (7200 Volts Line-To-Ground)	7 Minimum Fault Current Read on Current Diagram (7200 Volts Line-To-Ground)	8 Actual Maximum Fault Current Col. No.5 x $\frac{\text{Line-To-Gr. Volts}}{7200}$	9 Actual Minimum Fault Current Col. No. 7x $\frac{\text{Line-To-Gr. Volts}}{7200}$

FORM DS-90

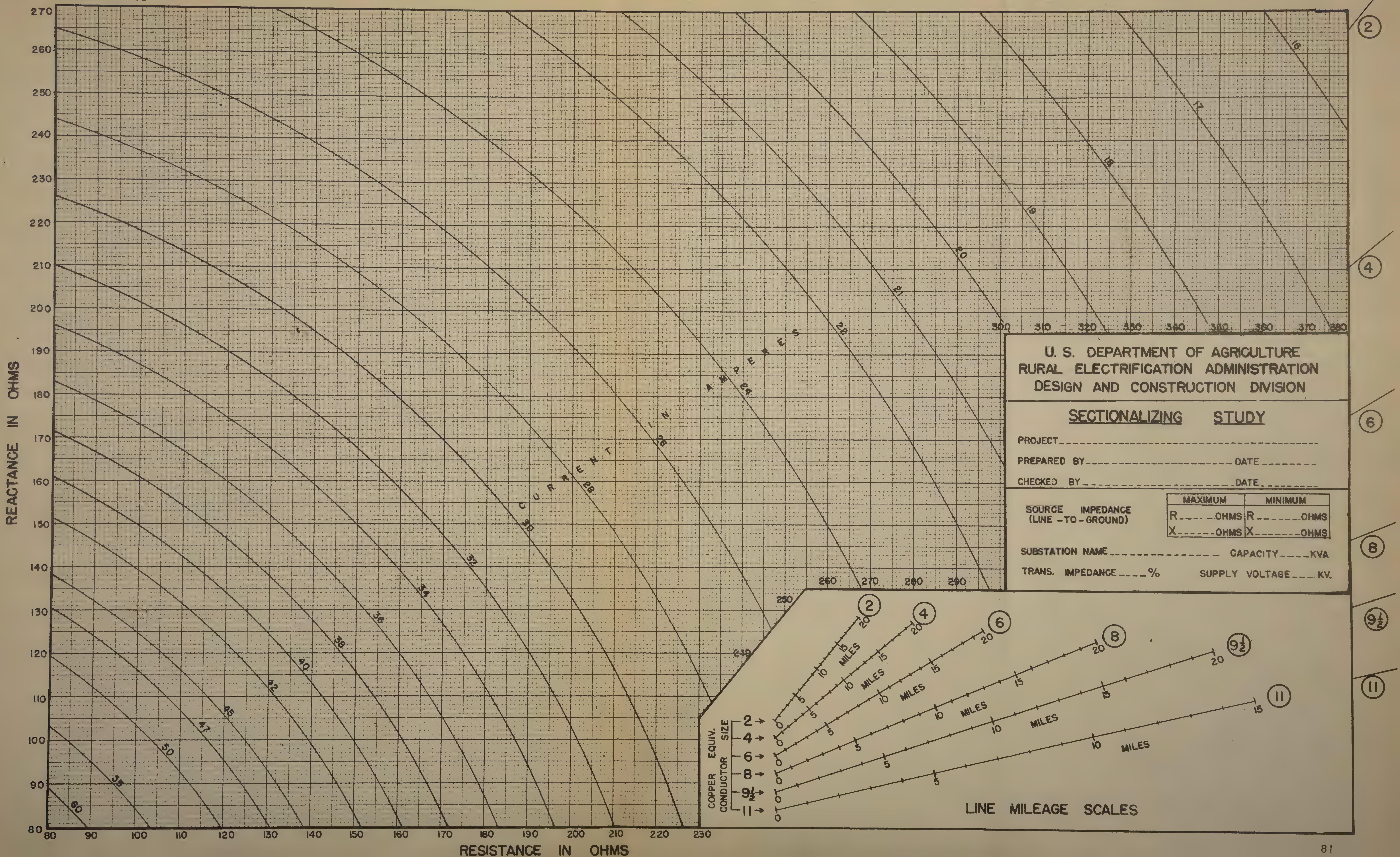
7200 VOLT SHORT CIRCUIT CURRENT DIAGRAM NO. 1

LINE-TO-GROUND FAULTS



FORM DS-92

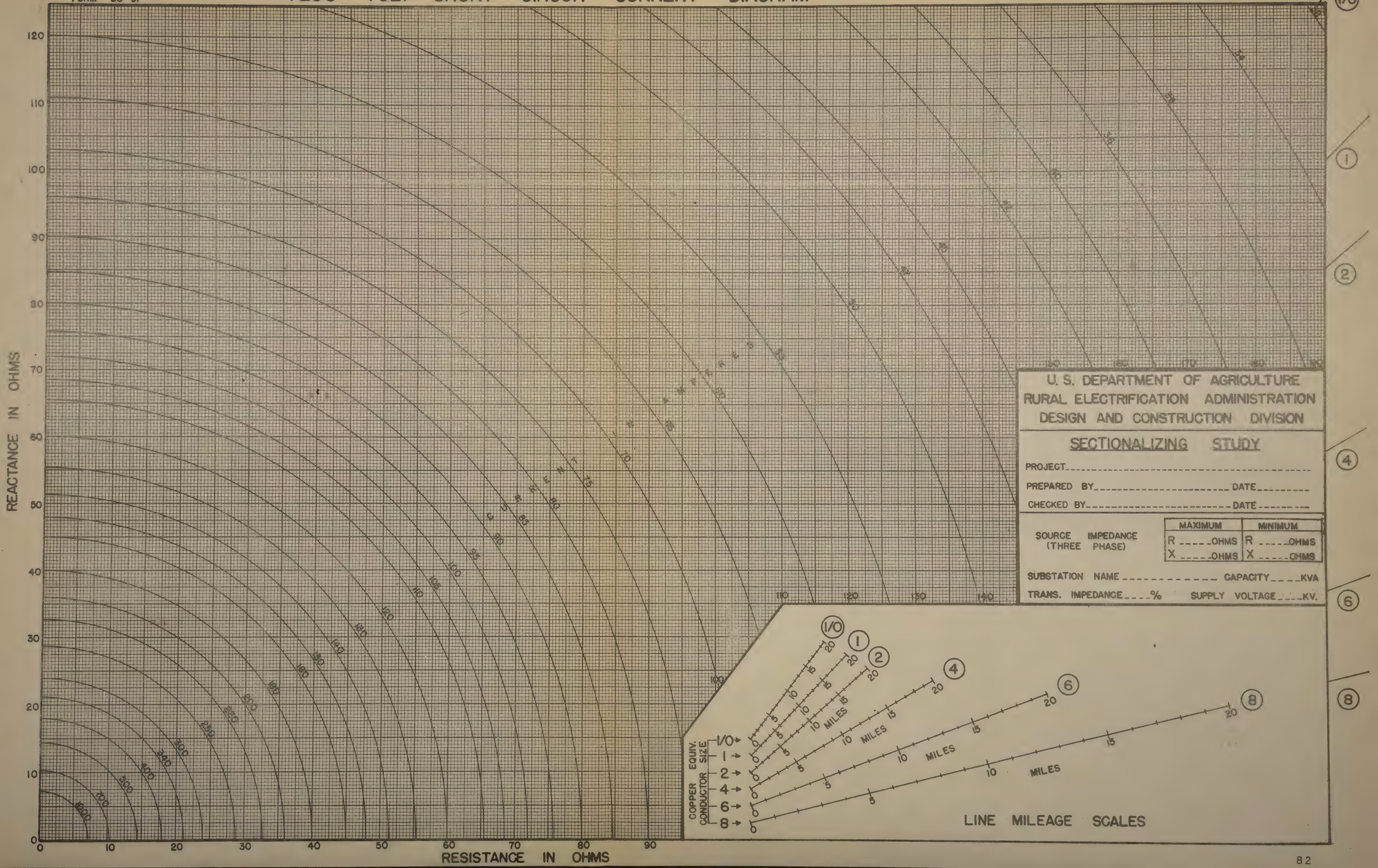
7200 VOLT SHORT CIRCUIT CURRENT DIAGRAM NO. 2 LINE-TO-GROUND FAULTS



FORM DS-91

7200 VOLT SHORT CIRCUIT CURRENT DIAGRAM

THREE PHASE FAULTS



U. S. DEPARTMENT OF AGRICULTURE
RURAL ELECTRIFICATION ADMINISTRATION
DESIGN AND CONSTRUCTION DIVISION

SECTIONALIZING STUDY

PROJECT______________________________

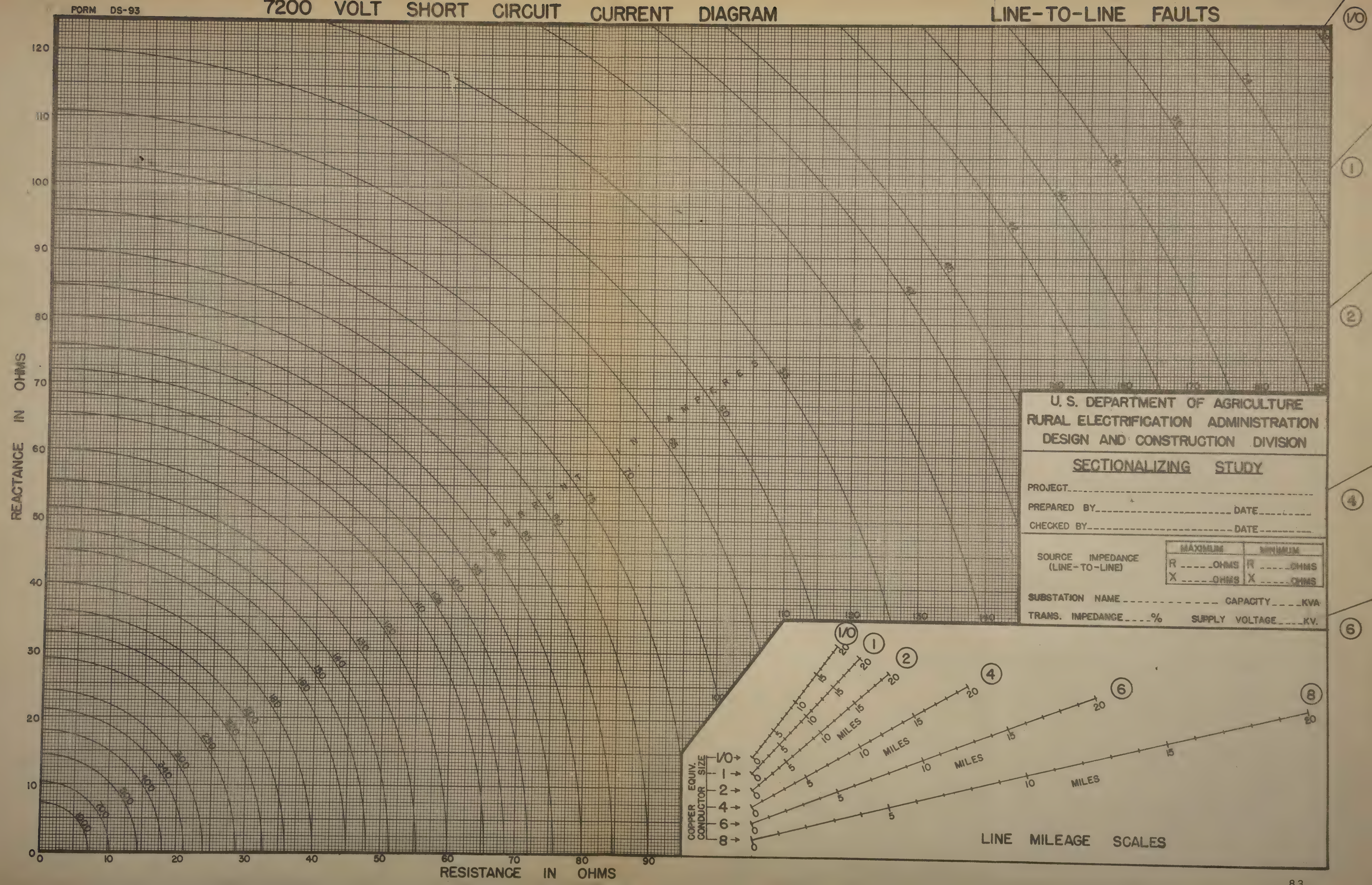
PREPARED BY____________________ DATE________

CHECKED BY_____________________ DATE________

SOURCE IMPEDANCE (THREE PHASE)	MAXIMUM	MINIMUM
	R ____OHMS	R ____OHMS
	X ____OHMS	X ____OHMS

SUBSTATION NAME____________ CAPACITY____KVA

TRANS. IMPEDANCE____% SUPPLY VOLTAGE____KV.


FORM DS-93
7200 VOLT SHORT CIRCUIT CURRENT DIAGRAM
LINE-TO-LINE FAULTS
REACTANCE IN OHMS
RESISTANCE IN OHMS
CURRENT IN AMPERES
U. S. DEPARTMENT OF AGRICULTURE
RURAL ELECTRIFICATION ADMINISTRATION
DESIGN AND CONSTRUCTION DIVISION
SECTIONALIZING STUDY
PROJECT
PREPARED BY DATE
CHECKED BY DATE
SOURCE IMPEDANCE (LINE-TO-LINE)
MAXIMUM
MINIMUM
R OHMS
X OHMS
SUBSTATION NAME
CAPACITY KVA
TRANS. IMPEDANCE %
SUPPLY VOLTAGE KV.
COPPER CONDUCTOR EQUIV. SIZE
1/0
1
2
4
6
8
MILES
LINE MILEAGE SCALES

SAMPLE PROBLEM

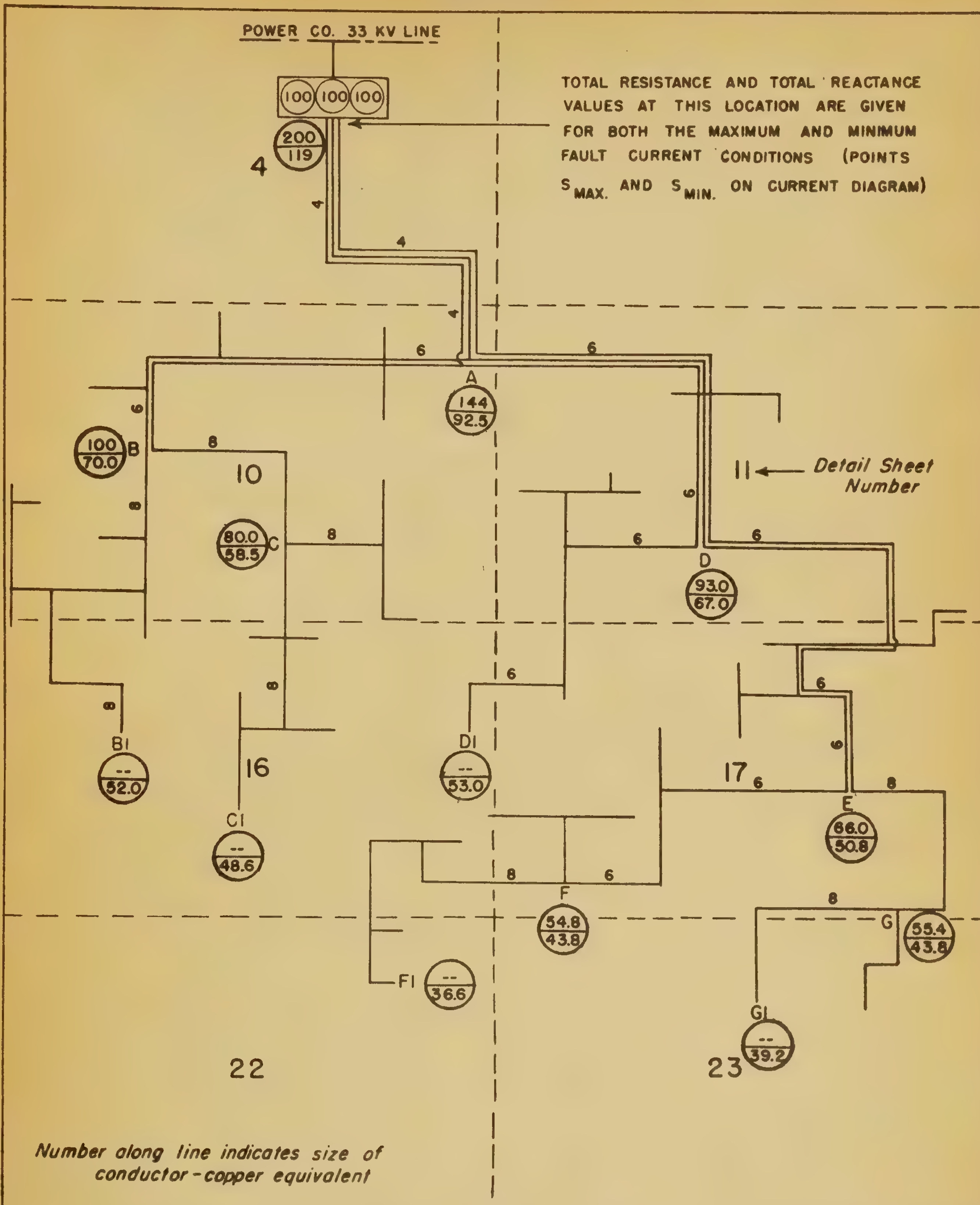
This sample problem is given for the purpose of illustrating the procedure of calculating the line-to-ground fault currents by the graphical method. A hypothetical distribution system is shown on the attached simplified circuit diagram. A fault resistance of 40 ohms is assumed. The resistance and reactance values on load side of the substation for line-to-ground faults for both the maximum and minimum condition are as follows:

	Line-to-Ground Faults
Maximum Condition:	
Resistance..	5.5 ohms
Reactance...	35.6 ohms
Minimum Condition:	
Resistance (Includes 40 ohm fault resistance)....	45.5 ohms
Reactance..	40.5 ohms

A current diagram and data sheet for the sample problem, showing the complete solution for determining the line-to-ground fault currents, are attached. You will note that points were not plotted on the current diagram for the maximum fault current at the end of the most distant taps, since it is necessary to know only the minimum currents at those points.

Consideration is not given to three phase and line-to-line fault currents in the sample problem, in view of the fact that the procedure for calculating these current is exactly the same as the procedure for determining line-to-ground fault currents. In making a sectionalizing study of an actual system which has three phase and V phase lines, three phase fault current calculations should be made for all points on the three phase lines using the three phase current diagram, and line-to-line fault current calculations should be made for all points on the three phase and V phase lines using the line-to-line current diagram. The starting points on the three phase diagram should be the total resistance and total reactance values for maximum and minimum conditions on the load side of the substation for three phase faults. The starting point on the line-to-line diagram should be the total resistance and total reactance values, for the maximum and minimum conditions, on the load side of the substation for line-to-line faults.

SAMPLE



NOTE: This drawing illustrates a problem.
For Requirements of Circuit Diagram, See Engineering Memo 154.
For Legend, See Style Sheet D.S.115 dated 6-1-45.

SCALE 1" = 3 MILES

DATE	REVISIONS

CIRCUIT DIAGRAM
RURAL ELECTRIFICATION ADM.

STATE	KEY	DETAIL	TOWN
SOME STATE	21		

Form DS-89

U. S. DEPARTMENT OF AGRICULTURE RURAL ELECTRIFICATION ADMINISTRATION	SECTIONALIZING STUDY Sheet 1 of 1 Sheets	Project Designation Somestate 21 Jones
Prepared by: Joe Blowe Date 11/8/43	Checked by: Date	System Line-To-Gr. Voltage 7200 Volts

1 Point	2 Preceding Point On Line Toward Substation	3 Miles from Previous Point On Line Toward Substation	4 Copper Conductivity Size Section From Previous Point	5 Type of Fault Calculated	6 Maximum Fault Current Read on Current Diagram (7200 Volts Line-To-Ground)	7 Minimum Fault Current Read on Current Diagram (7200 Volts Line-To-Ground)	8 Actual Maximum Fault Current Col.No.6 x Line-To-Gr. Volts / 7200	9 Actual Minimum Fault Current Col.No. 7 x Line-To-Gr. Volts / 7200
Sub					200	119		
A	Sub	8.2	#4		144	92.5		
B	A	9.0	#6	Line-to-Ground	100.0	70		
B_1	B	9.3	#8		---	52		
C	B	5.2	#8		80.0	58.5		
C_1	C	6.7	#8		---	48.6		
D	A	11.0	#6		93.0	67		
D_1	D	9.8	#6			53		
E	D	12.0	#6		66.0	50.8		
F	E	7.9	#6		54.8	43.8		
F_1	F	8.3	#8		---	36.6		

1 Point	2 Preceding Point On Line Toward Substation	3 Miles From Previous Point On Line Toward Substation	4 Copper Conductivity Size Section From Previous Point	5 Type of Fault Calculated	6 Maximum Fault Current Read on Current Diagram (7200 Volts Line-To-Ground)	7 Minimum Fault Current Read on Current Diagram (7200 Volts Line-To-Ground)	8 Actual Maximum Fault Current Col.No.6 x Line-To-Gr. Volts / 7200	9 Actual Minimum Fault Current Col.No.7 x Line-To-Gr., Volts / 7200
G	E	5.5	#8	L. to Gr.	55.4	43.8		
G_1	G	4.8	#8		--	39.2		

Note: Colums 8 and 9 are to be used only when system voltage is not 7.2/12.5 KV.

FORM DS-90

7200 VOLT SHORT CIRCUIT CURRENT DIAGRAM NO. 1

LINE-TO-GROUND FAULTS